

**BEFORE THE
PUBLIC SERVICE COMMISSION
OF THE DISTRICT OF COLUMBIA**

IN THE MATTER OF

**THE APPLICATION OF POTOMAC
ELECTRIC POWER COMPANY FOR
AUTHORITY TO INCREASE EXISTING
RETAIL RATES AND CHARGES FOR
ELECTRIC DISTRIBUTION SERVICE**

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Formal Case No. _____

VOLUME II of III:

**Direct Testimony and Exhibits of
Potomac Electric Power Company Witnesses
HEVERT, McGOWAN and HOOK**

July 8, 2011

R. B. HEVERT
Direct Testimony
DC P.S.C. - July, 2011

Introduced as:
PEPCO _____ (D)

POTOMAC ELECTRIC POWER COMPANY

BEFORE THE
DISTRICT OF COLUMBIA PUBLIC SERVICE COMMISSION
DIRECT TESTIMONY OF ROBERT B. HEVERT
FORMAL CASE NO. _____

1 Q. PLEASE STATE YOUR NAME, AFFILIATION AND BUSINESS ADDRESS.

2 A. My name is Robert B. Hevert, and I am President of
3 Concentric Energy Advisors, Inc. (Concentric). My
4 business address is 293 Boston Post Road West, Suite 500,
5 Marlborough, Massachusetts 01752.

6 Q. ON WHOSE BEHALF ARE YOU SUBMITTING THIS TESTIMONY?

7 A. I am submitting this testimony on behalf of Potomac
8 Electric Power Company (Pepco or the Company), a
9 wholly-owned operating subsidiary of Pepco Holdings, Inc.
10 (PHI).

11 Q. PLEASE BRIEFLY OUTLINE YOUR RESPONSIBILITIES AS PRESIDENT
12 OF CONCENTRIC.

13 A. In addition to providing consulting services, my
14 responsibilities at Concentric include the day-to-day
15 management of the firm and, along with other senior
16 officers, the development of the firm's resources and
17 capabilities, the development of new business and
18 clients, and the assurance of the quality and control of
19 services delivered to our firm's clients.

1 Q. PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND.

2 A. I hold a Bachelors degree in Business and Economics
3 from the University of Delaware, and an MBA with a
4 concentration in Finance from the University of
5 Massachusetts. Additionally, I hold the Chartered
6 Financial Analyst designation.

7 Q. PLEASE DESCRIBE YOUR EXPERIENCE IN THE ENERGY AND UTILITY
8 INDUSTRIES.

9 A. I have served as an executive and manager with other
10 consulting firms (REED Consulting Group and Navigant
11 Consulting, Inc.), as well as a financial officer of Bay
12 State Gas Company. I have provided testimony regarding
13 strategic and financial matters, including the cost of
14 capital, before several state utility regulatory agencies
15 as well as the Federal Energy Regulatory Commission
16 (FERC) on over 70 occasions, and have advised numerous
17 energy and utility clients on a wide range of financial
18 and economic issues including both asset and corporate
19 based transactions. Many of those assignments have
20 included the determination of the cost of capital for
21 transaction or other valuation purposes. I have provided
22 a summary of my professional and educational background,
23 including a list of my testimony in prior proceedings, in
24 Appendix A to my Direct Testimony.

1 Q. PLEASE DESCRIBE CONCENTRIC'S ACTIVITIES IN ENERGY AND
2 UTILITY ENGAGEMENTS.

3 A. Concentric provides regulatory, financial, and
4 economic advisory services to a large number of energy
5 and utility clients across North America. Our
6 regulatory, economic and market analysis services include
7 utility ratemaking and regulatory advisory services,
8 energy market assessments, market entry and exit
9 analysis, and energy contract negotiations. Our
10 financial advisory activities include merger, acquisition
11 and divestiture assignments, due diligence and valuation
12 assignments, project and corporate finance services, and
13 transaction support services. In addition, Concentric
14 provides litigation support services on a wide range of
15 financial and economic issues for clients throughout
16 North America.

17 PURPOSE AND OVERVIEW OF TESTIMONY

18 Q. WHAT IS THE PURPOSE OF YOUR DIRECT TESTIMONY?

19 A. The purpose of my Direct Testimony is to present
20 evidence and provide a recommendation regarding Pepco's
21 Return on Equity (ROE) and to assess the reasonableness
22 of its proposed capital structure.¹ My analyses and
23 recommendations are supported by the data presented in

¹ Throughout my Direct Testimony, I interchangeably use the terms "ROE" and "Cost of Equity."

1 Exhibits 1 through 10, which I have prepared directly, or
2 which others have prepared under my direction.

3 **Q. WHAT ARE YOUR CONCLUSIONS REGARDING THE APPROPRIATE COST**
4 **OF EQUITY FOR PEPCO?**

5 A. My analyses indicate that the Company's cost of
6 equity currently is within the range of 10.50% to 11.25%.
7 Based on the quantitative and qualitative analyses
8 discussed throughout the balance of my testimony, I
9 recommend that the District of Columbia Public Service
10 Commission (Commission) allow Pepco the opportunity to
11 earn an ROE of 10.75%.

12 **Q. PLEASE PROVIDE A BRIEF OVERVIEW OF THE ANALYSES THAT LED**
13 **TO YOUR ROE RECOMMENDATION.**

14 A. As discussed in more detail in Section IV, in light
15 of recent market conditions, and given the fact that
16 analysts and investors tend to use multiple methods in
17 developing their return requirements, it is extremely
18 important to consider the results of several analytical
19 approaches in determining Pepco's ROE (I discuss those
20 analyses in greater detail in Section IV). In order to
21 develop my ROE recommendation, I therefore applied the
22 Constant Growth Discounted Cash Flow (DCF) model, the
23 Capital Asset Pricing Model (CAPM), and the Bond Yield
24 Plus Risk Premium approach. As discussed later in my

1 testimony, it is important to consider a range of
2 factors, both quantitative and qualitative, in arriving
3 at an ROE determination. At the same time, I recognize
4 that in prior proceedings, the Commission has relied
5 substantially on the DCF approach in arriving at ROE
6 determinations.² Consequently, while I have continued to
7 include all three models in my testimony, I have given
8 more weight to the DCF.

9 In addition to the analyses discussed above, I also
10 have taken certain business risks into consideration when
11 developing my recommendation. Those risks include: (1)
12 the regulatory environment in which the Company operates;
13 and (2) the Company's proposed capital investment plan.
14 While I did not make any explicit adjustments to my ROE
15 estimates for those factors, I did take them into
16 consideration when determining where the Company's ROE
17 falls within the range of analytical results. In
18 addition, I have considered whether the Company's Bill
19 Stabilization Adjustment (BSA) mechanism has a measurable
20 effect on its Cost of Equity. Finally, in recognition of
21 the Commission's traditional practice of including
22 flotation costs as an item of expense in the cost of

² See, Formal Case No. 1076, *In the Matter of the Application of the Potomac Electric Power Company for Authority to Increase Existing Retail Rates and Charges for Electric Distribution Service*, Order No. 15710, March 2, 2010, at 25.

1 service and not an adjustment to the ROE,³ my
2 recommendation does not reflect an adjustment for the
3 effect of flotation costs associated with issuing common
4 equity. However, I have included a calculation of the
5 flotation cost adjustment to the ROE in the event that
6 the Commission does not authorize a flotation cost
7 expense in the cost of service.

8 **Q. HOW IS THE REMAINDER OF YOUR TESTIMONY ORGANIZED?**

9 A. The remainder of my testimony is organized in seven
10 sections. In Section I, I discuss the regulatory
11 guidelines and financial considerations pertinent to the
12 development of the rate of return. Section II briefly
13 describes the current capital market conditions and the
14 effect of those conditions on the Company's Cost of
15 Equity. Section III explains the criteria and process by
16 which I selected the group of proxy companies used to
17 estimate Pepco's Cost of Equity. Section IV explains the
18 bases and assumptions underlying the quantitative
19 approaches used to estimate the Company's ROE. Section V
20 provides a discussion of specific business risks and
21 costs that have a bearing on the Company's Cost of
22 Equity, Section VI discusses the Company's proposed

³ Id.

1 capital structure, and Section VII summarizes my
2 analyses, conclusions and recommendation.

3 **I. REGULATORY GUIDELINES AND FINANCIAL CONSIDERATIONS**

4 **Q. PLEASE DESCRIBE THE GUIDING PRINCIPLES TO BE USED IN**
5 **ESTABLISHING THE COST OF CAPITAL FOR A REGULATED UTILITY.**

6 A. The United States Supreme Court's precedent-setting
7 *Hope* and *Bluefield* cases established the basis for the
8 current standards for determining the fairness or
9 reasonableness of a utility's allowed ROE. Among the
10 standards established by the Court in those cases are:
11 (1) consistency with other businesses having similar or
12 comparable risks; (2) adequacy of the return to support
13 credit quality and access to capital; and (3) the
14 principle that the specific means of arriving at a fair
15 return are not important, only that the end result leads
16 to just and reasonable rates.⁴

17 **Q. DOES THE DISTRICT PRECEDENT PROVIDE SIMILAR GUIDANCE?**

18 A. Yes, it does.

19 In Order No. 12589, for example, the Commission
20 stated:

21 The Commission must also adhere to the standard
22 found in *Bluefield* and *Hope*, which hold that a

⁴ *Bluefield Waterworks & Improvement Co., v. Public Service Commission of West Virginia*, 262 U.S. 679 (1923); *Federal Power Commission v. Hope Natural Gas Co.*, 320 U.S. 591 (1944).

1 utility must be permitted a fair return
2 sufficient to attract capital investment.⁵

3 Based on those standards, the consequence of the
4 Commission's order in this proceeding should be to
5 provide the Company with the opportunity to earn an ROE
6 that is: (1) commensurate with returns on equity
7 investments in enterprises having comparable risks; (2)
8 sufficient to ensure the financial soundness of the
9 Company's operations; and (3) adequate to attract capital
10 at reasonable terms, thereby enabling it to provide safe,
11 reliable service. The allowed ROE should enable the
12 Company to finance capital expenditures at reasonable
13 rates and to maintain its financial flexibility over the
14 period during which rates are expected to remain in
15 effect.

16 **Q. IS IT IMPORTANT FOR A UTILITY TO BE ALLOWED THE**
17 **OPPORTUNITY TO EARN A RETURN THAT IS ADEQUATE TO ATTRACT**
18 **CAPITAL AT REASONABLE TERMS?**

19 **A.** Yes. A return that is adequate to attract capital
20 at reasonable terms will enable the Company to provide
21 safe, reliable service while maintaining its financial

⁵ Formal Case No. 989, *In the Matter of the Office of the People's Counsel's Complaint for a Commission-ordered Investigation into the Reasonableness of Washington Gas Light Company's Existing Rates; and In the Matter of the Application of Washington Gas Light Company, District of Columbia Division, for Authority to Increase Existing Rates and Charges for Gas Service*; Order No. 12589, October 29, 2002, at 13.

1 integrity. While the "capital attraction" and "financial
2 integrity" standards are important principles in normal
3 economic conditions, the practical implications of those
4 standards are even more pronounced in the current
5 financial environment. As discussed in more detail in
6 Section II, continued equity market volatility, together
7 with sustained increases in utility debt credit spreads
8 (i.e., the difference in debt yields of utilities with
9 varying credit ratings), have intensified the importance
10 of maintaining a strong financial profile.

11 **II. CURRENT CAPITAL MARKET ENVIRONMENT**

12 **Q. DO ECONOMIC CONDITIONS INFLUENCE THE REQUIRED COST OF**
13 **CAPITAL AND REQUIRED ROE?**

14 A. Yes. The required cost of capital, including the
15 ROE, is a function of prevailing and expected financial
16 market conditions. During times of capital market
17 instability, risk aversion increases, which causes
18 investors to seek the relative safety of U.S. Treasury
19 debt, resulting in lower Treasury yields. At the same
20 time, market volatility, as measured by indicators such
21 as the Chicago Board Options Exchange (CBOE) Volatility
22 Index (VIX), tends to increase. A direct result of
23 elevated volatility is a corresponding increase in the

1 risk premium required by investors as compensation for
2 taking on the risks associated with equity ownership.

3 To the extent that observable measures of
4 instability and risk aversion remain elevated relative to
5 historical norms, it would be incorrect to conclude that
6 the Cost of Equity has materially decreased. While there
7 is little question that the capital market dislocation
8 that began in late 2008 has moderated, market instability
9 and investor risk aversion remain at comparatively high
10 levels. That is especially true when viewed relative to
11 the conditions that existed prior to the recent financial
12 market dislocation.

13 **Q. WHAT ANALYSIS HAVE YOU CONDUCTED TO ASSESS CURRENT**
14 **CAPITAL MARKET CONDITIONS?**

15 A. As discussed below, I considered several
16 widely-recognized measures of investor risk perceptions,
17 including: (1) incremental credit spreads; (2) expected
18 volatility; and (3) the relationship between the dividend
19 yields of the proxy companies and Treasury yields.
20 Except where noted, I compared current market conditions
21 to the two-year period prior to the 2007-2009 recession.
22 As shown in Table 1, those metrics indicate that current
23 levels of risk aversion are significantly higher than the
24 levels observed prior to the recent recession, and are

much closer to the levels experienced during the 2002-2003 capital market contraction.

Table 1: Risk Sentiment Indicators⁶

	May 31, 2011 ⁷	Pre-recession (Jan-2006 through Nov-2007)	Jan-2002 through Dec-2003
<i>Credit Spreads</i> (Moody's Utility Bond Index) Baa-rated bond to A rated bond	0.42%	0.25%	0.46%
<i>Dividend Yield Spreads</i> 10-year Treasury to Proxy Group	-1.14%	0.34%	-1.77%
<i>Market Volatility</i> CBOE VXV and CBOE VIX Futures ⁸	21.87	14.87 ⁹	24.63 ¹⁰

A. Incremental Credit Spreads

Q. HOW HAVE CREDIT SPREADS BEEN AFFECTED BY CURRENT MARKET CONDITIONS?

A. The "credit spread" is the incremental return required by debt investors to take on the default risk associated with securities of differing credit quality. As shown in Table 1, and as Chart 1 demonstrates, the current 90-day moving average spread of the Moody's Baa-

⁶ Bloomberg Professional Service.

⁷ Represents the 90-trading day average as of May 31, 2011, except as noted otherwise.

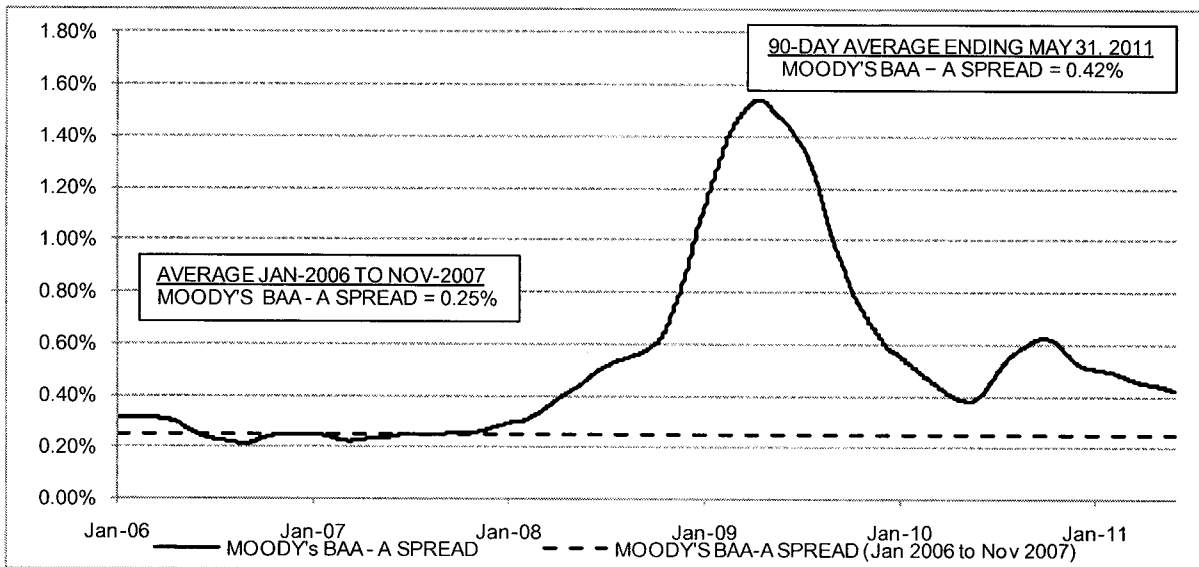
⁸ Represents the 30-trading day average pricing of six-month forward volatility. Please note that the VIX is a one-month measure of volatility, while the VXV is a three-month measure.

⁹ Represents the average VIX measured from January 2006 to November 2007.

¹⁰ Represents the average VIX, measured from January 2002 to December 2003.

1 rated utility bond index to the Moody's A-rated utility
 2 bond index is 17 basis points above - or 68.00% higher
 3 than - the comparable average credit spread immediately
 4 prior to the onset of the recent recession.

5 **Chart 1: Moody's Utility Bond Index Baa-A Credit Spread**



6 **Q. WHAT ARE THE IMPLICATIONS OF HIGHER CREDIT SPREADS AS**
 7 **COMPARED TO THE LONG-TERM AVERAGE?**

8 A. To the extent that credit spreads have increased, it
 9 is an observable measure of the capital markets'
 10 increased risk aversion; increased risk aversion clearly
 11 is associated with an increased cost of equity. In
 12 addition, there is a clear and well-established inverse
 13 relationship between the level of interest rates and the
 14 equity risk premium. Consequently, lower utility bond
 15 yields, which are a function of lower Treasury yields, do
 16 not necessarily imply a correspondingly lower cost of

1 equity, particularly considering the current level of
2 credit spreads that are higher than the long-term
3 average.

4 **B. Equity Market Volatility**

5 **Q. PLEASE DISCUSS CHANGES IN EQUITY MARKET VOLATILITY.**

6 A. A directly observable measure of market volatility
7 is the VIX. The VIX represents the implied (one month)
8 volatility on the S&P 500 Index and as such, is an
9 observable measure of investors' expectations of
10 volatility and, therefore, risk. Since the inception of
11 the VIX in 1990, its average has been approximately
12 20.35.¹¹ In contrast, forward-looking estimates of
13 volatility as of May 31, 2011 (as measured by futures
14 prices on the VIX and the CBOE S&P 500 VXV index, which
15 is a three-month volatility index) are approximately
16 21.87. The currently anticipated level of volatility is
17 measurably above the pre-recessionary period (i.e.,
18 January 2006 to November 2007) during which the VIX
19 averaged 14.87, and more consistent with the volatility
20 experienced in the previous market contraction in 2002
21 and 2003, during which the VIX averaged 24.63. As
22 discussed earlier, there is a direct relationship between

¹¹ The 20.35 percent average volatility is approximately equal to the long run (i.e., 1926-2010) market volatility reported by Morningstar, Inc.

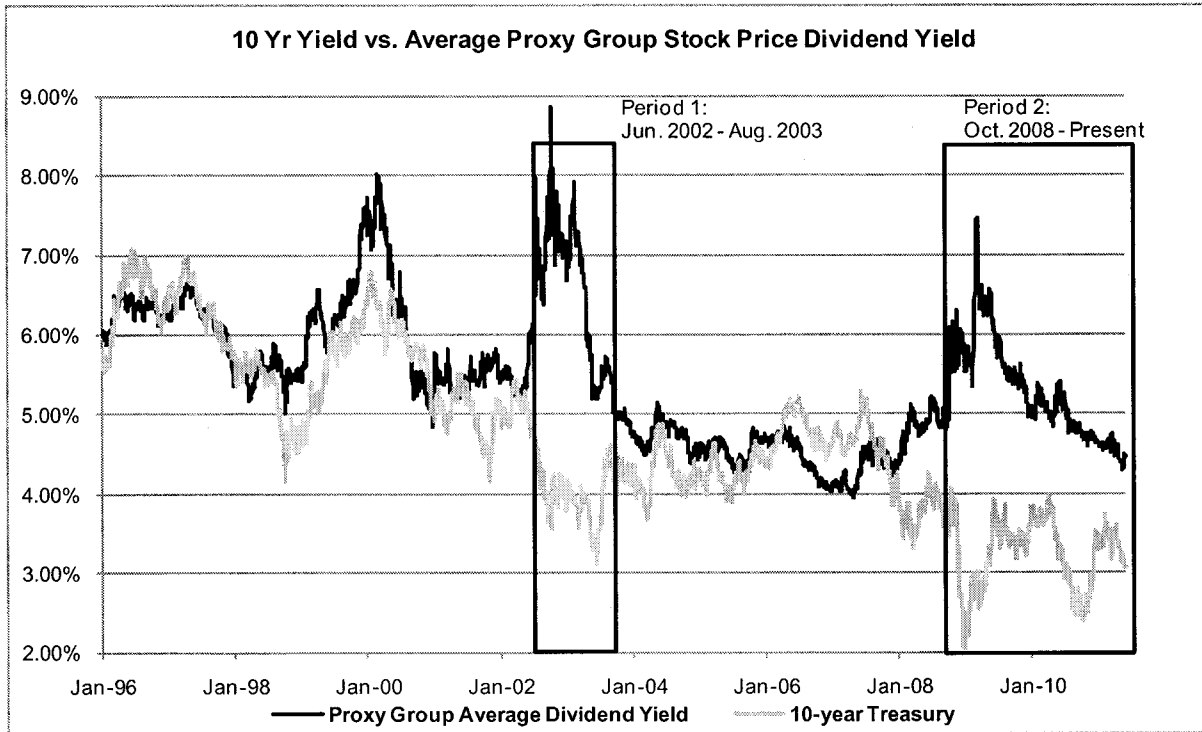
1 market volatility and the equity risk premium and, as
2 such, the comparatively high forward-looking volatility
3 measures indicate higher, not lower required equity
4 returns.

5 **C. Yield Spreads**

6 **Q. PLEASE DISCUSS YOUR ANALYSIS OF THE RELATIONSHIP BETWEEN**
7 **DIVIDEND YIELDS AND TREASURY YIELDS.**

8 A. As a preliminary matter, the "yield spread" is the
9 difference between long-term Treasury yields and dividend
10 yields. Investors often consider yield spreads in their
11 assessment of security valuation and capital market
12 conditions. As shown in Chart 2, the 2008 - 2009
13 financial dislocation created the first significant
14 widening of the yield spread (based on the proxy group
15 average dividend yield) in five years. Prior to that
16 time, the most recent period during which these yields
17 were significantly divergent was from mid-2002 through
18 mid-2003, which itself was a period of credit and equity
19 valuation contraction.

Chart 2: Treasury Yield/Dividend Yield Divergence
(January 1, 1995 – May 31, 2011)



A 2009 article in *The Wall Street Journal* noted this same relationship between utility dividend yields and the ten-year Treasury yield, observing that, "dividend yields have tended to track the yield on 10-year Treasuries closely."¹² The article went on to note that:

Regulated utilities' dividend yields decoupled from Treasury yields in December 2007, as the U.S. recession began. After the initial flight to quality cut yields on Treasuries, particularly after Lehman Brothers collapsed in September 2008, the Federal Reserve's policy of buying up government debt has helped keep them low.¹³

¹² Denning, Liam, "A Short Circuit in the Stock Market," *The Wall Street Journal*, October 23, 2009, at C10.

¹³ *Id.* See, also, Credit Suisse, "A Thought...Regulated Utilities = Investment Opportunity?" March 10, 2009, at 30.

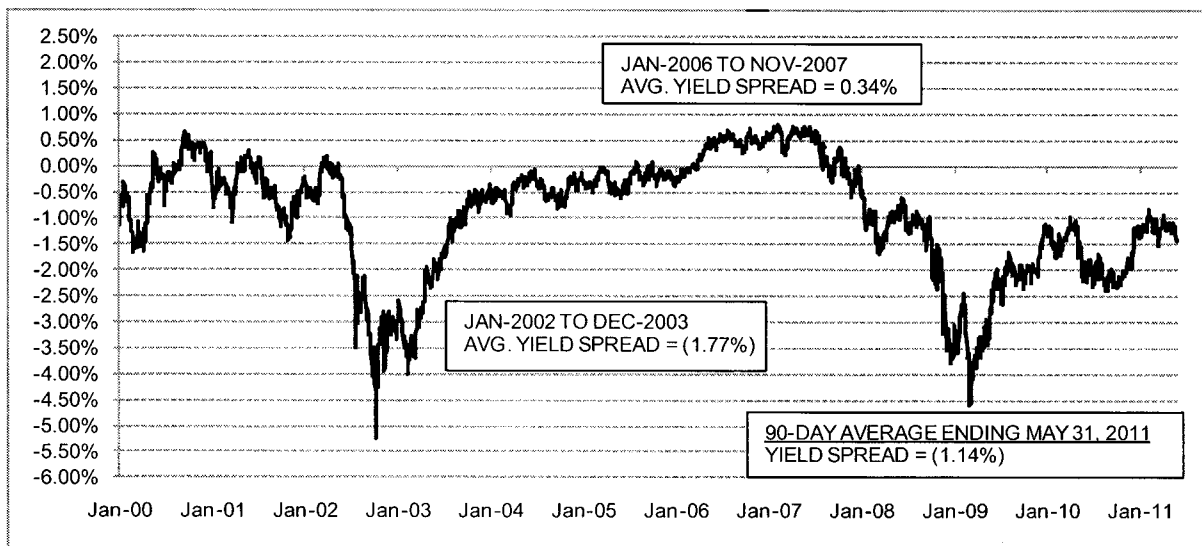
1 Q. WHY IS THE CONTINUED DIVERGENCE BETWEEN UTILITY DIVIDEND
2 YIELDS AND THE TEN-YEAR TREASURY YIELD RELEVANT IN
3 DETERMINING THE COMPANY'S COST OF EQUITY?

4 A. First, as suggested by *The Wall Street Journal*,
5 investors often look to the relationships among financial
6 metrics to assess current and expected levels of market
7 stability. To the extent that such relationships
8 materially and persistently deviate from long-term norms,
9 it may be an indication of continuing or expected
10 instability. In the case of the yield spread, the fact
11 that continued Federal intervention in the capital
12 markets has been required to maintain relatively low
13 Treasury yields introduces yet another significant
14 element of capital market uncertainty. Again, investors
15 require increased returns to be compensated for taking on
16 such risk.

17 The widened yield spread, which began in 2008, has
18 continued since that article was published. From January
19 2000 through September 15, 2008 (*i.e.*, the time of the
20 Lehman Brothers bankruptcy filing), the average yield
21 spread between ten-year Treasury securities and the proxy
22 group average dividend yield was negative 59 basis

points. Considering the two-year period¹⁴ prior to the recession, the average yield on ten-year Treasury securities exceeded the proxy group average dividend yield by approximately 34 basis points. As Chart 3 indicates, the 90-day average yield spread as of May 31, 2011 was negative 114 basis points.

Chart 3: Proxy Company Yield Spread



Q. WHAT CONCLUSIONS DO YOU DRAW FROM THOSE ANALYSES?

A. First, these analyses indicate that capital-intensive companies such as Pepco continue to face the risks and costs associated with an unstable capital market environment. Second, as to the prospect for increasing interest rates, it is well established that utility stock prices decline as interest rates

¹⁴ This analysis includes the 23 months beginning January 2006 and ending November 30, 2007, just prior to the start of the recent recession, as defined by the National Bureau of Economic Research.

1 increase. Such lower valuation levels reflect increased
2 costs of attracting the equity capital needed to fund
3 utilities' capital investment programs, and, therefore,
4 reflect the need for a commensurately higher ROE. As
5 noted in the March 2011 Federal Reserve Open Market
6 Committee (FOMC) Minutes:

7 The spread between the expected real equity
8 return for S&P 500 firms and the real 10-year
9 Treasury yield - a measure of the equity risk
10 premium - narrowed a bit more over the
11 intermeeting period *but continued to be quite*
12 *elevated relative to longer-term norms.*¹⁵

13 Third, it also is clear that the current market
14 conditions are similar to the 2002-2003 market
15 dislocation that affected all market segments, including
16 utilities. One outcome of the 2002-2003 market
17 dislocation was a renewed emphasis on capital market
18 access and the importance of maintaining a strong
19 financial profile, both of which are equally important in
20 the current market environment.

21 **Q. WHAT ELSE DO THESE ANALYSES DEMONSTRATE?**

22 A. The analyses described above also demonstrate that
23 the assessment of capital market conditions must be made
24 in the context of multiple, observable indices. It would
25 be inappropriate, for example, to view the current level

¹⁵ Minutes of the Federal Open Market Committee, March 15, 2011, at 4.
(Emphasis added.)

1 of Treasury yields as indicative of a lower cost of
2 capital when consensus estimates call for a substantial
3 increase in long-term interest rates. As a result of the
4 "flight to quality" that occurred during the 2008 - 2009
5 market instability, yields on United States Treasury
6 securities were driven to historically low levels; the
7 same is true in the current market environment.¹⁶ As
8 investors begin to reallocate capital to securities with
9 higher expected risks and returns (all else being equal),
10 Treasury yields necessarily will increase. Given the
11 continuing capital market instability, it is extremely
12 important to assess the reasonableness of any financial
13 model's results in the context of observable market data.
14 To the extent that certain ROE estimates are incompatible
15 with such metrics or inconsistent with basic financial
16 principles, it is appropriate to consider whether
17 alternative estimation techniques are likely to provide
18 more meaningful and reliable results.

¹⁶ "Flight to quality" refers to investors' shifting of asset allocation from higher to lower, or lowest, risk investable assets.

1 Q. HOW SHOULD CURRENT ECONOMIC CONDITIONS BE TAKEN INTO
2 CONSIDERATION IN DETERMINING THE APPROPRIATE ROE FOR THE
3 COMPANY?

4 A. In my view, the authorized rate of return in this
5 proceeding will provide a signal to the financial
6 community concerning the ability of the Company to meet
7 its capital needs during a period in which its capital
8 investments are increasing, and both debt and equity
9 investors are requiring higher rates of return. If
10 investors perceive a supportive regulatory environment,
11 as evidenced by an allowed rate of return that
12 compensates the Company at a level commensurate with its
13 risk, the Company should be able to attract equity
14 capital at a reasonable cost.

15 III. PROXY GROUP SELECTION

16 Q. PLEASE EXPLAIN WHY YOU HAVE USED PROXY COMPANIES TO
17 DETERMINE THE COST OF EQUITY FOR PEPCO.

18 A. First, it is important to bear in mind that the Cost
19 of Equity for a given enterprise depends on the risks
20 attendant to the business in which the company is
21 engaged. According to financial theory, the value of a
22 given company is equal to the aggregate market value of
23 its constituent business units. The value of the
24 individual business units reflects the risks and

1 opportunities inherent in the business sectors in which
2 those units operate. In this proceeding, we are focused
3 on estimating the Cost of Equity for Pepco, a rate
4 regulated, wholly-owned subsidiary of PHI. Because the
5 ROE is a market-based concept, and given that Pepco is
6 not publicly traded, it is necessary to establish a group
7 of companies that are both publicly traded and comparable
8 to Pepco in certain fundamental business and financial
9 respects to serve as its "proxy" in the ROE estimation
10 process.

11 Even if Pepco were a publicly traded entity, it is
12 possible that transitory events could bias its market
13 value in one way or another over a given period of time.
14 A significant benefit of employing a proxy group,
15 therefore, is the mitigation of the effects of anomalous
16 events that may be associated with any one company. The
17 proxy companies used in my analyses all possess a set of
18 operating and risk characteristics that are substantially
19 comparable to Pepco, and therefore provide a reasonable
20 basis for the derivation and assessment of ROE estimates.

1 Q. ARE YOU AWARE OF ANY RECENT COURT DECISIONS THAT
2 HIGHLIGHT THE IMPORTANCE OF DEVELOPING A PROXY GROUP OF
3 COMPANIES THAT IS OF COMPARABLE RISK TO THE SUBJECT
4 COMPANY?

5 A. Yes. The importance of selecting a proxy group that
6 is comparable in general financial and business risk to
7 the subject company was affirmed by the United States
8 Court of Appeals for the District of Columbia in the
9 *Petal Gas Storage* decision. The Court of Appeals
10 acknowledged that the goal of a proxy group is to rely on
11 companies that are of similar risk to the subject company
12 for determining the subject company's Cost of Equity:

13 That proxy group arrangements must be risk-
14 appropriate is the common theme in each
15 argument. The principle is well-established.
16 See *Hope Natural Gas Co.*, 320 U.S. at 603
17 ("[T]he return to the equity owner should be
18 commensurate with returns on investments in
19 other enterprises having corresponding
20 risks."); *CAPP I*, 254 F.3d at 293 ("[A] utility
21 must offer a risk-adjusted expected rate of
22 return sufficient to attract investors."). The
23 principle captures what proxy groups do,
24 namely, provide market-determined stock and
25 dividend figures from public companies
26 comparable to a target company for which those
27 figures are unavailable. *CAPP I*, 254 F.3d at
28 293-94. Market determined stock figures
29 reflect a company's risk level and, when
30 combined with dividend values, permit
31 calculation of the "risk-adjusted expected rate
32 of return sufficient to attract investors."¹⁷

33 ***

¹⁷ *Petal Gas Storage v. FERC*, 496 F.3d 695, 699 (D.C. Cir. 2007), at 5.

1 What matters is that the overall proxy group
2 arrangement makes sense in terms of relative
3 risk and, even more importantly, in terms of
4 the statutory command to set "just and
5 reasonable" rates, 15 U.S.C. § 717c, that are
6 "commensurate with returns on investments in
7 other enterprises having corresponding risks"
8 and "sufficient to assure confidence in the
9 financial integrity of the enterprise . . .
10 [and] maintain its credit and . . . attract
11 capital." *Hope Natural Gas Co.*, 320 U.S. at
12 603.¹⁸

13 Thus, regulatory commissions and analysts alike recognize
14 the importance of developing a proxy group that
15 adequately represents the ongoing risks and prospects of
16 the subject company.

17 **Q. PLEASE PROVIDE A SUMMARY PROFILE OF PEPCO.**

18 A. As noted earlier, Pepco is a wholly-owned operating
19 subsidiary of PHI (NYSE: POM). The Company provides
20 electric transmission, distribution and default supply
21 service to approximately 256,000 customers in the
22 District of Columbia and 531,000 customers in Maryland.¹⁹

23 The following table provides summary financial and
24 operating statistics for Pepco for the past three years:

¹⁸ Id. at 7.

¹⁹ Pepco Holdings, SEC Form 10-K for the fiscal year ended December 31,
2010, at 5.

Table 2: Pepco Operating and Financial Results
2008 To 2010²⁰ (millions of dollars)

	2008	2009	2010
Electric Customers	767,000	778,000	787,000
Regulated Electric Revenue	\$978	\$947	\$1,068
Total Net Income	\$116	\$106	\$108
Net Electric PPE	\$2,928	\$3,078	\$3,161

Pepco has investment grade ratings from each of the credit rating agencies; the Company's current corporate credit rating is BBB+ (outlook: stable) according to Standard and Poor's (S&P), Baa2 (outlook: stable) according to Moody's, and BBB+ (outlook: stable) according to Fitch.²¹

Q. HOW DID YOU SELECT THE COMPANIES INCLUDED IN YOUR PROXY GROUP?

A. I began with the companies that Value Line classifies as "Electric Utilities," which comprise a group of 53 domestic U.S. utilities. I then simultaneously applied the following screening criteria:

- I excluded companies that do not pay cash dividends, because such companies cannot be analyzed using the

²⁰ 2009 and 2010 operating and financial data from Pepco Holdings, SEC Form 10-K for the fiscal year ended December 31, 2010 at 89-90, 220 and 234. 2008 operating and financial data from corresponding 10-K for the fiscal year ended December 31, 2009 at 96-97, 212, and 227. Includes District of Columbia and Maryland.

²¹ Source: SNL Financial.

DCF model, which is the primary method used in my analysis;

- I selected companies that have long-term earnings growth estimates from at least two utility industry equity analysts;
- I selected proxy companies that have an S&P senior unsecured bond and/or corporate ratings of BBB- to AA (S&P or Moody's equivalent, as the case may be);
- I excluded companies whose average regulated operating income for the years 2008, 2009 and 2010 comprised less than 60.00% of the consolidated total;
- I excluded companies whose average regulated electric operating income over 2008, 2009 and 2010 represented less than 90.00% of total regulated operating income; and
- I eliminated any companies that are currently known to be party to a merger or other transformative transaction.

Q. DID YOU INCLUDE PHI IN YOUR ANALYSIS?

A. No, I did not. It is my practice to exclude the subject company, or its parent holding company, from the

1 proxy group in order to avoid the circular logic that
2 would otherwise result.

3 **Q. WHY DID YOU INCLUDE INTEGRATED UTILITIES IN YOUR PROXY**
4 **GROUP, WHEN PEPKO IS A TRANSMISSION AND DISTRIBUTION**
5 **COMPANY?**

6 A. When combined with my other screening criteria,
7 screening out all companies that own generation would
8 have left my proxy group with only one company. That
9 company, ITC Holdings Corp. (ITC) is a FERC regulated
10 transmission-only company, and as such is not
11 fundamentally comparable to Pepco. As a practical
12 matter, therefore, it would not be feasible to construct
13 a reasonable proxy group of electric utilities that do
14 not own physical generating assets. I therefore
15 concluded that expanding my proxy group to include
16 integrated electric companies is a reasonable approach
17 for the purpose of estimating the Company's Cost of
18 Equity.

19 **Q. WHAT COMPANIES MET THE SCREENING CRITERIA FOR YOUR**
20 **INITIAL PROXY GROUP?**

21 A. Strict adherence to the criteria discussed above
22 resulted in an initial proxy group of the following
23 thirteen companies.

Table 3: Initial Proxy Group

Company	Ticker
American Electric Power	AEP
Cleco, Corp.	CNL
Edison International	EIX
Empire District Electric	EDE
Great Plains Energy, Inc.	GXP
Hawaiian Electric	HE
IDACORP, Inc.	IDA
Integrus/WPS Resources	TEG
Otter Tail Corporation	OTTR
Pinnacle West Capital	PNW
Portland General	POR
Southern Company	SO
Westar Energy	WR

Q. DOES THIS CONSTITUTE YOUR FINAL PROXY GROUP?

A. No, it does not. My initial set of screening criteria produced a group of thirteen potential proxy companies. I then examined the operating profile of each of those thirteen companies to be certain that none of them displayed characteristics that were inconsistent with my intent to produce a proxy group that is fundamentally similar to the Company. As a result of that examination, I have made three modifications to the initial screening results.

First, my review revealed that Edison International (EIX) reported significant unregulated losses in 2009; those losses were in excess of 45.00% of EIX's regulated

1 utility operating income. According to EIX's 2009 SEC
2 Form 10-K, the operating losses were the result of a
3 global tax settlement with the Internal Revenue Service
4 and termination of cross-border leases, which caused
5 EIX's unregulated competitive power and financial
6 services segment to record an approximately \$920 pre-tax
7 million loss.²² Given the extent of those losses, it is
8 difficult to assess the extent to which the regulated
9 electric utility operations would be expected to
10 contribute to the company's consolidated financial
11 performance in the near and longer terms. Consequently,
12 I have excluded EIX from my final proxy group.

13 Second, Otter Tail Corp. (Otter Tail) reported
14 significant losses in the operating income of several
15 non-regulated business segments in 2009 and 2010, due to
16 recessionary market conditions in those segments. As a
17 result, operating income from regulated operations
18 represented the majority of the reported operating income
19 in those years. However, since the process of estimating
20 the ROE necessarily is forward looking, it is important
21 to consider whether the electric utility operations will
22 continue to be the majority of operating income in the

²² See, Edison International, SEC Form 10-K for the fiscal year ended December 31, 2009, at 71 and 104.

1 future to establish whether the company's operations and
2 risks are comparable to the subject company.

3 Reviewing Otter Tail's SEC Form 10-K, the \$14.7
4 million loss experienced in 2010 in the Manufacturing
5 segment was due to economic conditions and a \$15.6
6 million net-of-tax asset impairment.²³ In addition, the
7 Wind Energy segment experienced a loss of \$21.2 million
8 in 2010.²⁴ Value Line projects a significant increase in
9 the earnings from the manufacturing subsidiary in 2011,
10 noting that the backlog for that business is 37.00%
11 higher than the year prior.²⁵ Similarly, Value Line
12 projects growth in the construction segment. Given the
13 extent of the 2010 losses and analyst projections for
14 2011, it is difficult to assess the degree to which
15 regulated electric utility operations would be expected
16 to contribute to the company's consolidated financial
17 performance in the near and longer terms. Therefore, I
18 have excluded Otter Tail from my final proxy group.

19 Third, and finally, similar to Otter Tail and EIX,
20 Integrys Energy Group, Inc. (Integrys) also experienced
21 significant losses during the three year period that I
22 relied on to develop my proxy group. In 2008, the

²³ Otter Tail Corporation 2010 SEC Form 10-K, at 43 and 85.

²⁴ Id. at 85.

²⁵ Value Line Report on Otter Tail Corp, March 25, 2011.

1 company reported operating losses of \$118.30 million in
2 Integrys Energy Services Non-regulated Segment
3 Operations.²⁶ In 2009, the Natural Gas Utility Segment
4 experienced an operating loss of \$114.6 million,
5 primarily as the result of a non-cash goodwill impairment
6 loss of \$284.6 million.²⁷ Regarding the impairment
7 charge, the company noted that:

8 Key factors contributing to the impairment
9 charge included disruptions in the global
10 credit and equity markets and the resulting
11 increase in the weighted-average cost of
12 capital used to value the natural gas utility
13 operations, and the negative impact that the
14 global decline in equity markets had on the
15 valuation of natural gas distribution companies
16 in general.²⁸

17 Since the composition of the ongoing operations of
18 Integrys is somewhat uncertain, I have excluded Integrys
19 from the final proxy group.

20 My final proxy group therefore consists of the ten
21 companies noted in Table 4 (below).

²⁶ Integrys 2010 SEC Form 10-K, at 40.

²⁷ Integrys 2009 SEC Form 10-K, at 35.

²⁸ Id. at 107.

Table 4: Final Proxy Group

Company	Ticker
American Electric Power	AEP
Cleco, Corp.	CNL
Empire District Electric	EDE ²⁹
Great Plains Energy, Inc.	GXP
Hawaiian Electric	HE
IDACORP, Inc.	IDA
Pinnacle West Capital	PNW
Portland General	POR
Southern Company	SO
Westar Energy	WR

IV. COST OF EQUITY ESTIMATION

Q. PLEASE BRIEFLY DISCUSS THE COST OF EQUITY IN THE CONTEXT OF THE REGULATED RATE OF RETURN.

A. Regulated utilities primarily use common equity and long-term debt to finance their permanent property, plant and equipment. The Rate of Return (ROR) for a regulated utility is based on its weighted average cost of capital, which weighs the costs of the individual sources of capital by their respective book values. While the cost

²⁹ I recognize that on May 22, 2011, Empire District Electric (EDE) sustained major storm damage to its service territory. While the company subsequently paid its most recent dividend on May 27, 2011, it also announced a two-quarter temporary dividend suspension for the remainder of the year. Given the announced temporary nature of its dividend suspension, I have retained EDE in the final proxy group. In addition, exclusion of EDE from the proxy group would not change the range of results discussed in my testimony or my recommended ROE in this proceeding.

1 of debt can be directly observed, the Cost of Equity must
2 be estimated based on observable market information.

3 **Q. HOW IS THE REQUIRED ROE ESTIMATED FROM MARKET**
4 **INFORMATION?**

5 A. The required ROE is estimated using one or more
6 analytical techniques that rely on market-based data to
7 quantify investor expectations regarding required equity
8 returns. I then apply my informed judgment, based on the
9 results of those analyses, to determine where within the
10 range of results the Cost of Equity for Pepco falls. The
11 resulting Cost of Equity serves as the recommended ROE
12 for ratemaking purposes. As a general proposition, the
13 key consideration in determining the Cost of Equity is to
14 ensure that the methods employed reasonably reflect
15 investors' view of the financial markets in general, and
16 the risks and prospects associated with the subject
17 company's common equity in particular.

18 **Q. WHAT METHODS DID YOU USE TO DETERMINE PEPCO'S COST OF**
19 **EQUITY?**

20 A. I used the Constant Growth DCF model as the primary
21 approach to my analysis. I then considered the results
22 of the CAPM and an alternative Risk Premium approach in
23 assessing the reasonableness of the DCF results in
24 developing my ROE recommendation. As discussed in more

1 detail below, it is extremely important to consider
2 current and expected market conditions in the application
3 of those models in the interpretation of their results.
4 Consequently, a reasonable ROE estimate appropriately
5 considers alternate methods and the reasonableness of
6 their individual and collective results in the context of
7 observable market conditions.

8 **Q. WHY DO YOU BELIEVE IT IS IMPORTANT TO USE MORE THAN ONE**
9 **ANALYTICAL APPROACH?**

10 A. Because the cost of equity is not directly
11 observable, it must be estimated based on both
12 quantitative and qualitative information. When faced
13 with the task of estimating the ROE, analysts and
14 investors are inclined to gather and evaluate as much
15 relevant data as reasonably can be analyzed. As a
16 result, a number of models have been developed to
17 estimate the Cost of Equity. For that reason, Concentric
18 uses multiple approaches to estimate the Cost of Equity
19 used in performing valuations in the context of our
20 financial advisory and transaction practices.

21 As a practical matter, however, all of the models
22 used to estimate the Cost of Equity are subject to
23 limiting assumptions or other analytic constraints.
24 Consequently, many finance texts recommend using multiple

1 approaches when estimating the Cost of Equity. For
2 example, Copeland, Koller and Murrin,³⁰ suggest using the
3 CAPM and Arbitrage Pricing Theory model, while Brigham
4 and Gapenski³¹ recommend the CAPM, DCF and "bond yield
5 plus risk premium" approaches.

6 In essence, analysts and academics understand that
7 ROE models are tools to be used in the ROE estimation
8 process and that strict adherence to any single approach,
9 or the specific results of any single approach, can lead
10 to flawed and irrelevant conclusions. That position is
11 consistent with the *Hope* and *Bluefield* finding that it is
12 the analytical result, as opposed to the method, that is
13 controlling in arriving at ROE determinations. A
14 reasonable ROE estimate therefore considers alternative
15 methods, observable market data, and the reasonableness
16 of their individual and collective results.

17 Consequently, it is both prudent and appropriate to
18 use multiple methods in order to mitigate the effects of
19 assumptions and inputs associated with relying
20 exclusively on any single approach. Such use, however,

³⁰ Tom Copeland, Tim Koller and Jack Murrin, Valuation: Measuring and Managing the Value of Companies, 3rd ed. (New York: McKinsey & Company, Inc., 2000), at 214.

³¹ Eugene Brigham, Louis Gapenski, Financial Management: Theory and Practice, 7th Ed. (Orlando: Dryden Press, 1994), at 341.

1 must be tempered with due caution as to the results
2 generated by each individual approach.

3 **Q. HAVE YOU RELIED ON ONE APPROACH MORE THAN OTHERS FOR**
4 **PURPOSES OF ESTIMATING THE ROE FOR PEPSCO?**

5 A. Yes. In recognition of the Commission's prior
6 reliance on the DCF approach for purposes of determining
7 the cost of equity,³² I have relied primarily on the
8 results of that model for purposes of my ROE estimation.

9 **A. *The Constant Growth DCF Model***

10 **Q. ARE DCF MODELS WIDELY USED TO DETERMINE THE COST OF**
11 **EQUITY FOR REGULATED UTILITIES?**

12 A. Yes. DCF models are widely used in regulatory
13 proceedings and have a sound theoretical basis, although
14 neither the DCF model nor any other model can be applied
15 without considerable judgment when selecting the data and
16 interpreting the results. In its simplest form, the DCF
17 model expresses the Cost of Equity as the sum of the
18 expected dividend yield and long-term growth rate.

19 **Q. PLEASE DESCRIBE THE DCF APPROACH.**

20 A. The DCF approach is based on the theory that a
21 stock's current price represents the present value of all

³² See, e.g., Formal Case No. 1076, *In the Matter of the Application of the Potomac Electric Power Company for Authority to Increase Existing Rates and Charges for Electric Distribution Service*, March 2, 2010, at 25.

expected future cash flows. In its most general form, the DCF model is expressed as follows:

$$P_0 = \frac{D_1}{(1+k)} + \frac{D_2}{(1+k)^2} + \dots + \frac{D_\infty}{(1+k)^\infty} \quad [1]$$

Where P_0 represents the current stock price, $D_1 \dots D_\infty$ are all expected future dividends, and k is the discount rate, or required ROE. Equation [1] is a standard present value calculation that can be simplified and rearranged into the familiar form:

$$k = \frac{D(1+g)}{P_0} + g \quad [2]$$

Equation [2] is often referred to as the "Constant Growth DCF" model in which the first term is the expected dividend yield and the second term is the expected long-term growth rate.

Q. WHAT ASSUMPTIONS ARE REQUIRED FOR THE CONSTANT GROWTH DCF MODEL?

A. The DCF model requires the following assumptions:

- (1) a constant growth rate for earnings and dividends;
- (2) a stable dividend payout ratio; (3) a constant price-to-earnings multiple; and (4) a discount rate greater than the expected growth rate. To the extent that any of these assumptions is violated, considered

1 judgment and/or specific adjustments should be applied to
2 the results.

3 ***B. Dividend Yield for the DCF Model***

4 **Q. WHAT MARKET DATA DID YOU USE TO CALCULATE THE DIVIDEND**
5 **YIELD IN YOUR DCF MODEL?**

6 A. The dividend yield is based on the proxy companies'
7 current annualized dividend, and average closing stock
8 prices over the 30-, 90-, and 180-trading days ended May
9 31, 2011.

10 **Q. WHY DID YOU USE 30-DAY, 90-DAY AND 180-DAY AVERAGING**
11 **PERIODS?**

12 A. I believe it is important to use an average of
13 recent trading days to calculate the term P_0 in the DCF
14 model to ensure that the calculated ROE is not skewed by
15 anomalous events that may affect stock prices on any
16 given trading day. In that regard, the averaging period
17 should be reasonably representative of expected capital
18 market conditions over the long term. At the same time,
19 it is important to reflect the extraordinary conditions
20 that have defined the financial markets over the recent
21 past. In my view, the use of the 30, 90 and 180-day
22 averaging periods reasonably balances those concerns.

1 Q. PUTTING ASIDE THE ISSUE OF THE AVERAGING PERIOD, DID YOU
2 MAKE ANY ADJUSTMENTS TO THE DIVIDEND YIELD TO ACCOUNT FOR
3 PERIODIC GROWTH IN DIVIDENDS?

4 A. Yes. Because utility companies tend to increase
5 their quarterly dividends at different times throughout
6 the year, it is reasonable to assume that dividend
7 increases will be evenly distributed over calendar
8 quarters. Given that assumption, it is reasonable to
9 apply one-half of the expected annual dividend growth for
10 purposes of calculating the expected dividend yield
11 component of the DCF model. This adjustment ensures that
12 the expected dividend yield is, on average,
13 representative of the coming twelve-month period, and
14 does not overstate the aggregated dividends to be paid
15 during that time. Accordingly, the DCF estimates
16 provided in Exhibit (D)-1 reflect one-half of the
17 expected growth in the dividend yield component of the
18 model.³³

³³ Application of one-half of the expected growth rate to the dividend yield is also consistent with the Commission's practice as discussed in Formal Case No. 1076, *In the Matter of the Application of the Potomac Electric Power Company for Authority to Increase Existing Rates and Charges for Electric Distribution Service*, March 2, 2010, at 25.

C. Growth Rates for the DCF Model

Q. IS IT IMPORTANT TO SELECT APPROPRIATE MEASURES OF LONG-TERM GROWTH IN APPLYING THE DCF MODEL?

A. Yes. In its constant growth form, the DCF model (i.e., Equation [2]) assumes a single growth rate in perpetuity. Accordingly, in order to reduce the long-term growth rate to a single measure, one must assume a constant payout ratio, and that earnings per share, dividends per share and book value per share all grow at the same constant rate. Eventually, however, dividend and book value growth can only be sustained by earnings growth. Consequently, it is important to incorporate a variety of sources of long-term earnings growth into the Constant Growth DCF model.³⁴

Q. PLEASE SUMMARIZE YOUR INPUTS TO THE CONSTANT GROWTH DCF MODEL.

A. I applied the DCF model to the proxy group of ten electric utility companies using the following inputs for the price and dividend terms:

³⁴ This is also consistent with Commission practice. See, Formal Case No. 1076, *In the Matter of the Application of the Potomac Electric Power Company for Authority to Increase Existing Rates and Charges for Electric Distribution Service*, March 2, 2010, at 25.

- The average daily closing prices for the 30 trading days, 90 trading days, and 180 trading days ended May 31, 2011 for the term P_0 ; and
- The annualized dividend per share as of May 31, 2011 for the term D_0 .

I then calculated the DCF results using each of the following growth terms:

- The Zacks consensus long-term earnings growth estimates;
- The First Call consensus long-term earnings growth estimates; and
- The Value Line earnings growth estimates.

D. DCF Model Results

Q. PLEASE SUMMARIZE THE RESULTS OF YOUR DCF ANALYSES.

A. Table 5 (below), (see also Exhibit (D)-1), presents the results of the DCF analyses. As shown in that table, the DCF model produces a range of mean results from 10.71% to 10.96%; the mean high results range from 11.87% to 12.12%.

Table 5: Discounted Cash Flow Analyses Results

	Mean Low	Mean	Mean High
30-Day Average	9.58%	10.71%	11.87%
90-Day Average	9.72%	10.85%	12.01%
180-Day Average	9.83%	10.96%	12.12%

Q. HOW DID YOU CALCULATE THE MEAN HIGH AND MEAN LOW DCF RESULTS?

A. I calculated the mean high DCF result using the maximum growth rate (i.e., the maximum of the Zack's, First Call and Value Line EPS growth rates) in combination with the dividend yield for each of the proxy group companies. Thus, the mean high result reflects the average maximum DCF result for the proxy group. I used a similar approach to calculate the mean low results, using the minimum growth rate for each proxy group company.

Q. DID YOU UNDERTAKE ANY ADDITIONAL ANALYSES TO ASSESS YOUR DCF MODEL RESULTS?

A. Yes, I also used the CAPM and the Risk Premium approaches as means of testing the reasonableness of my DCF results.

E. CAPM Analysis

Q. PLEASE BRIEFLY DESCRIBE THE GENERAL FORM OF THE CAPITAL ASSET PRICING MODEL.

A. The CAPM is a risk premium approach that estimates the Cost of Equity for a given security as a function of

a risk-free return plus a risk premium (to compensate investors for the non-diversifiable or "systematic" risk of that security). As shown in Equation [3], the CAPM is defined by four components, each of which must theoretically be a forward-looking estimate:

$$K_e = r_f + \beta(r_m - r_f) \quad [3]$$

where:

K_e = the required market ROE;

β = Beta coefficient of an individual security;

r_f = the risk free rate of return; and

r_m = the required return on the market as a whole.

In this specification, the term $(r_m - r_f)$ represents the Market Risk Premium. According to the theory underlying the CAPM, because unsystematic risk can be diversified away, investors should be concerned only with systematic or non-diversifiable risk. Non-diversifiable risk is measured by the Beta coefficient, which is defined as:

$$\beta = \frac{\text{Covariance}(r_e, r_m)}{\text{Variance}(r_m)} \quad [4]$$

The variance of the market return, noted in Equation [4], is a measure of the uncertainty of the general market, and the covariance between the return on a specific security and the market reflects the extent to which the

1 return on that security will respond to a given change in
2 the market return. Thus, the Beta coefficient represents
3 the non-diversifiable risk of the security relative to
4 the overall market.

5 Q. DO YOU HAVE CONCERNS ABOUT THE CAPM BASED ON CURRENT AND
6 EXPECTED MARKET CONDITIONS?

7 A. Yes, I do. First, as noted above, the risk free
8 rate, " r_f ", in the CAPM formula is represented by the
9 interest rate on long-term U.S. Treasury securities.
10 During the financial dislocation, investors reacted to
11 the extraordinary levels of market volatility discussed
12 earlier by investing in low-risk securities such as
13 Treasury bonds. Consequently, if measured on a
14 historical basis, the first term in the model (i.e., the
15 risk-free rate) is lower than it would have been absent
16 the elevated degree of risk aversion that has, at least
17 in part, resulted in historically low Treasury yields.

18 In addition, as a result of the extraordinary loss
19 in equity values during 2008, the Market Risk Premium,
20 when measured on a historical basis, actually decreased
21 from the prior year, even though other measures of
22 investor sentiments, including market volatility and
23 credit spreads, indicated extremely high levels of risk
24 aversion. That result is, of course, counter-intuitive.

1 While the 2009 market rally resulted in a somewhat higher
2 historical Market Risk Premium, it still remains below
3 its pre-financial crisis level. Consequently, the Market
4 Risk Premium component of the model also should reflect
5 current, forward-looking market data.

6 Finally, Beta coefficients reported by Value Line
7 and Bloomberg calculate the Beta coefficient over
8 historical periods of 60 and 24 months, respectively.³⁵
9 During the recent financial market dislocation, the
10 relationship between the returns of the proxy group
11 companies and the S&P 500 was considerably different than
12 the relationship observed in the current market
13 environment. As a result, those Beta coefficients may
14 not be reasonable measures of current systematic risk.

15 **Q. WITH THOSE QUALIFICATIONS IN MIND, WHAT ASSUMPTIONS DID**
16 **YOU USE IN YOUR CAPM MODEL?**

17 A. I used the current 30-day average yield on 30-year
18 Treasury bonds (*i.e.*, 4.34%) and the near-term projected
19 30-year Treasury yield (*i.e.*, 4.88%) as my estimate of
20 the risk-free rate. In addition, for the reasons
21 discussed above (*e.g.*, the decrease in the Market Risk
22 Premium as measured on a historical basis despite

³⁵ As discussed below, while Bloomberg enables the analyst to calculate Beta coefficients over a range of periods, the default calculation period is 24 months.

1 elevated levels of risk aversion), I did not use a
2 historical average for the Market Risk Premium; rather, I
3 developed two forward-looking (ex-ante) estimates.

4 **Q. PLEASE DESCRIBE YOUR FIRST APPROACH TO ESTIMATING THE**
5 **MARKET RISK PREMIUM.**

6 A. The first approach is based on the expected return
7 on the S&P 500 Index, less the current 30-year Treasury
8 bond yield. The expected return on the S&P 500 is
9 calculated using the Constant Growth DCF model discussed
10 earlier in my testimony for the companies in the S&P 500
11 index for which long-term earnings projections are
12 available (companies with such projections represent
13 97.31% of the index market capitalization).

14 **Q. PLEASE DESCRIBE THE SECOND APPROACH USED TO ESTIMATE THE**
15 **EX-ANTE MARKET RISK PREMIUM.**

16 A. The second ex-ante approach assumes a constant
17 Sharpe Ratio, which is the ratio of the risk premium
18 relative to the risk, or standard deviation, of a given
19 security or index of securities. The Sharpe Ratio is
20 relied upon by financial professionals to assess how much
21 additional return an investor receives for holding a
22 risky (i.e., more volatile) asset rather than a risk-free
23 (i.e., less volatile) asset. The formula for calculating
24 the Sharpe Ratio is expressed as follows:

1 $S(X) = (R_x - R_f) / \text{Std Dev } (X)$ [5]

2 where:

3 X = the investment;

4 R_x = the average return of X ;

5 R_f = the best available rate of return of a risk
6 free security; and

7 Std Dev = the standard deviation of R_x .

8 As shown in Exhibit (D)-3, the constant Sharpe Ratio
9 is the ratio of the historical Market Risk Premium of
10 6.70% (the numerator of Equation 5) and the historical
11 market volatility of 20.28% (the denominator of Equation
12 5).³⁶ The expected Market Risk Premium then is calculated
13 as the product of the Sharpe Ratio and the expected
14 market volatility. To measure expected volatility, I
15 relied on the thirty-day average of the CBOE three-month
16 volatility index (*i.e.*, the VXV) and the same thirty-day
17 average of settlement prices of futures on the CBOE's
18 one-month volatility index (*i.e.*, the VIX) for August
19 through October 2011. Both the VIX and the VXV are
20 measures of implied market expectations of near-term
21 volatility derived from options on the S&P 500 index.

³⁶ Calculated from the Morningstar data. See Morningstar Inc., 2011 Ibbotson Stocks, Bonds, Bills and Inflation, Valuation Yearbook, Large Company Stocks: Total Returns Table B-1, at 162-163.

1 Q. WHAT MEASURES OF THE BETA COEFFICIENT DID YOU USE IN YOUR
2 CAPM MODEL?

3 A. With respect to Beta coefficients, I considered two
4 methods of calculation. My first approach simply used
5 the average reported Beta from Bloomberg and Value Line
6 for the proxy group companies. Both of those services
7 adjust their calculated (or "raw") Beta coefficients to
8 reflect the tendency of Beta coefficients to regress to
9 the market mean of 1.00, and (as noted earlier) Value
10 Line calculates Beta coefficients over a five-year
11 period, while Bloomberg's calculation is based on two
12 years of data. I also calculated Beta coefficients over
13 a more recent time period to provide a current view as to
14 investors' perspectives with respect to "systematic"
15 risk.

16 Q. PLEASE DESCRIBE HOW YOU CALCULATED THE MEAN ADJUSTED BETA
17 COEFFICIENT FOR YOUR PROXY GROUP.

18 A. As shown in Equation 5, the Beta coefficient is
19 calculated as the ratio of the covariance between the
20 individual security returns and the market returns, to
21 the variance of the market returns. To arrive at a
22 single estimate of the Beta coefficient for the proxy
23 group, I first averaged the weekly returns of the twelve
24 proxy companies. Calculating the covariance between the

1 proxy group's mean weekly returns and the weekly returns
2 of the S&P 500 for the most recent twelve months produces
3 the numerator of the Beta coefficient calculation for the
4 proxy group. As noted above, the denominator in the
5 calculation is the variance of weekly returns for the S&P
6 500.³⁷ As shown in Exhibit (D)-4, this method results in
7 a proxy group mean raw Beta coefficient of 0.598.
8 Adjusting the raw Beta coefficient for the tendency to
9 regress toward the market Beta coefficient of 1.0 results
10 in an adjusted Beta coefficient of 0.732.³⁸

11 **Q. HOW AND WHY DID YOU ADJUST THE RAW BETA COEFFICIENT?**

12 A. I adjusted my raw Beta coefficient consistent with
13 the method used by Bloomberg. This approach multiplies
14 the raw Beta coefficient (*i.e.*, 0.598) by 0.667, and adds
15 0.333 to that product. That approach results in the
16 adjusted Beta coefficient of 0.732 (*i.e.*, $[0.598 \times 0.667]$
17 $+ 0.333 = 0.732$). The purpose of such adjustments is to
18 reflect the results of substantial academic research

³⁷ It is worthwhile noting that averaging twelve individual Beta coefficients for each of the proxy group companies would produce the same result as calculating a single beta based on the average of the twelve companies' weekly returns.

³⁸ The raw Beta and adjusted Beta coefficients calculated using this approach are identical to the Beta coefficients calculated by Bloomberg when assuming the identical holding period.

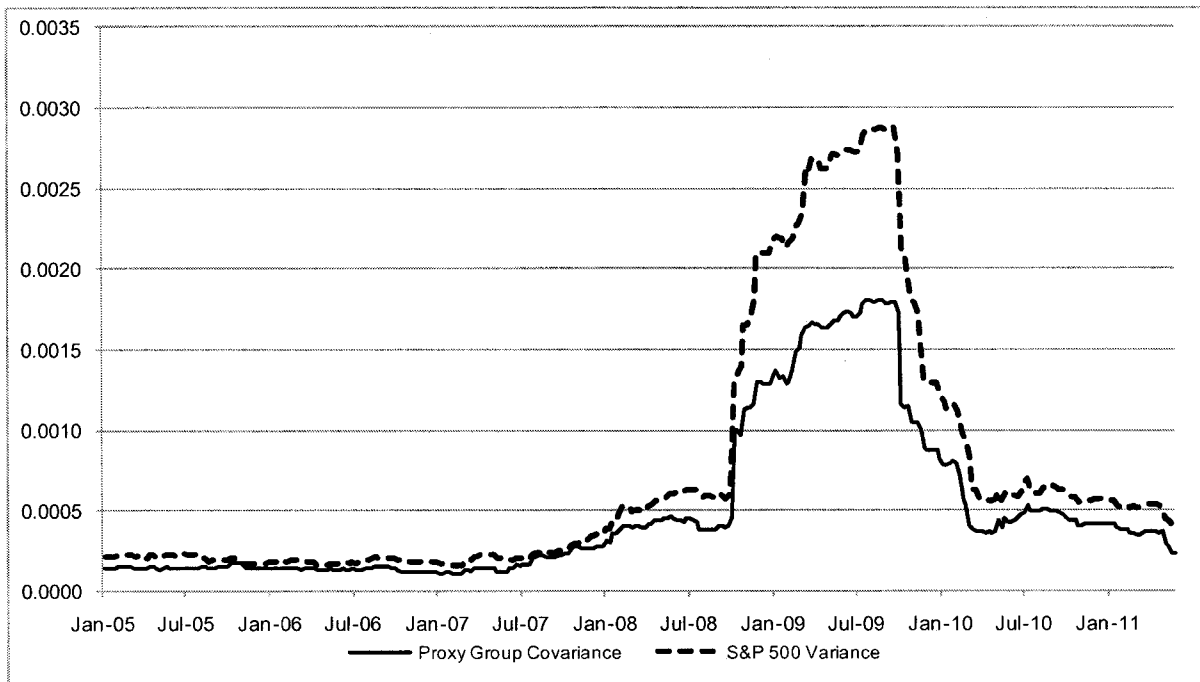
1 indicating that over time raw Beta coefficients tend to
2 regress to the market mean of 1.00.³⁹

3 **Q. PLEASE EXPLAIN WHY YOU RELIED ON A TWELVE-MONTH ESTIMATE**
4 **OF THE PROXY GROUP MEAN ADJUSTED BETA COEFFICIENT.**

5 A. As noted earlier, Value Line and Bloomberg calculate
6 Beta coefficients for each company over historical
7 periods of 60 and 24 months, respectively. Chart 4
8 (below) illustrates the relationship between the
9 covariance of average weekly returns for the proxy group
10 and the variance in the returns of the S&P 500, the two
11 components of the Beta coefficient calculation. During
12 the recent financial market dislocation, the relationship
13 between the returns of the proxy group companies and the
14 S&P 500 was considerably different than has been
15 experienced in the current market environment. In order
16 to capture a more current period than the Bloomberg
17 two-year calculation period, I based my analysis on a
18 twelve-month calculation period.

³⁹ The regression tendency of Beta coefficients to converge to 1.0 over time is well known and widely discussed in financial literature. See Blume, Marshall E., *On the Assessment of Risk*, The Journal of Finance, Vol. 26, No. 1, March 1971, at 1-10.

**Chart 4: Proxy Group Average Covariance and S&P 500
Variance (Rolling twelve month calculation)**



**Q. IS YOUR TWELVE-MONTH BETA COEFFICIENT OF 0.732 REASONABLE
RELATIVE TO LEVELS THAT WERE OBSERVED PRIOR TO THE
FINANCIAL MARKET CRISIS?**

A. Yes. In September 2007, one year prior to the Lehman Brothers bankruptcy filing, the average Beta coefficient for my proxy group was 0.96. As of June 30, 2008, the Beta coefficient for this same group was 0.84. Based on those historical measures, it is my view that the twelve-month average Beta of 0.73 is reasonable compared to levels before the financial market crisis.

Q. HOW DID YOU APPLY YOUR CAPM?

A. I relied on the ex-ante risk premium and near-term Beta coefficient to calculate the CAPM model using both

1 the current 30-day average yield on the 30-year U.S.
2 Treasury bond and near-term projections of the 30-year
3 Treasury bond yield as the risk-free rate. I also
4 performed the same calculation using the average Value
5 Line and Bloomberg Beta coefficients. As noted in
6 Exhibit (D)-3, the use of ex-ante market risk premia and
7 risk-free rates produces a range of results that is
8 generally consistent with the range of results produced
9 by the other calculation methods.

10 **Q. WHAT ARE THE RESULTS OF YOUR CAPM ANALYSES?**

11 A. As shown in Table 6 (below), (see also Exhibit
12 (D)-3), the CAPM analysis based on the twelve-month Beta
13 coefficient suggests an ROE range of 9.62% to 10.99%.
14 Alternatively, relying on an average of the Value Line
15 and Bloomberg estimates of Beta coefficients results in a
16 range of returns of 9.68% to 11.05%.

Table 6: Ex-Ante CAPM Results

	Sharpe Ratio Derived Market Risk Premium	DCF Derived Market Risk Premium
<i>Twelve-month Beta Coefficient</i>		
Current 30-Year Treasury (4.34%)	9.62%	10.44%
Projected 30-Year Treasury (4.88%)	10.17%	10.99%
<i>Average Value Line and Bloomberg Beta Coefficient</i>		
Current 30-Year Treasury (4.34%)	9.68%	10.50%
Projected 30-Year Treasury (4.88%)	10.22%	11.05%

F. Bond Yield Plus Risk Premium Analysis

Q. PLEASE DESCRIBE THE BOND YIELD PLUS RISK PREMIUM APPROACH YOU EMPLOYED.

A. In general terms, the Bond Yield Plus Risk Premium approach is based on the fundamental principle that equity investors bear the residual risk associated with ownership, and therefore require a premium over the return they would have earned as a bondholder. That is, since returns to equity holders are more risky than returns to bondholders, equity investors must be compensated for bearing that risk. Risk premium approaches, therefore, estimate the Cost of Equity as the sum of the equity risk premium and the yield on a particular class of bonds. As noted in my discussion of the CAPM, since the equity risk premium is not directly

1 observable, it typically is estimated using a variety of
2 approaches, some of which incorporate *ex-ante* estimates
3 of the Cost of Equity, and others that consider
4 historical or *ex-post* estimates. In the case of the CAPM,
5 those estimates are with respect to the return on the
6 broad market. An alternative approach is to use actual
7 authorized returns for electric utilities as the
8 historical measure of the Cost of Equity to determine the
9 equity risk premium.

10 **Q. WHAT DID YOUR BOND YIELD PLUS RISK PREMIUM ANALYSIS**
11 **REVEAL?**

12 A. As shown on Chart 5, from 1992 through May 31, 2011,
13 there was, in fact, a strong negative relationship
14 between risk premia and interest rates. To estimate that
15 relationship, I conducted a regression analysis using the
16 following equation:

17
$$RP = a + b(T) \quad [6]$$

18 where:

19 RP = Risk Premium (difference between allowed ROEs
20 and 30-Year Treasury Bond yield)

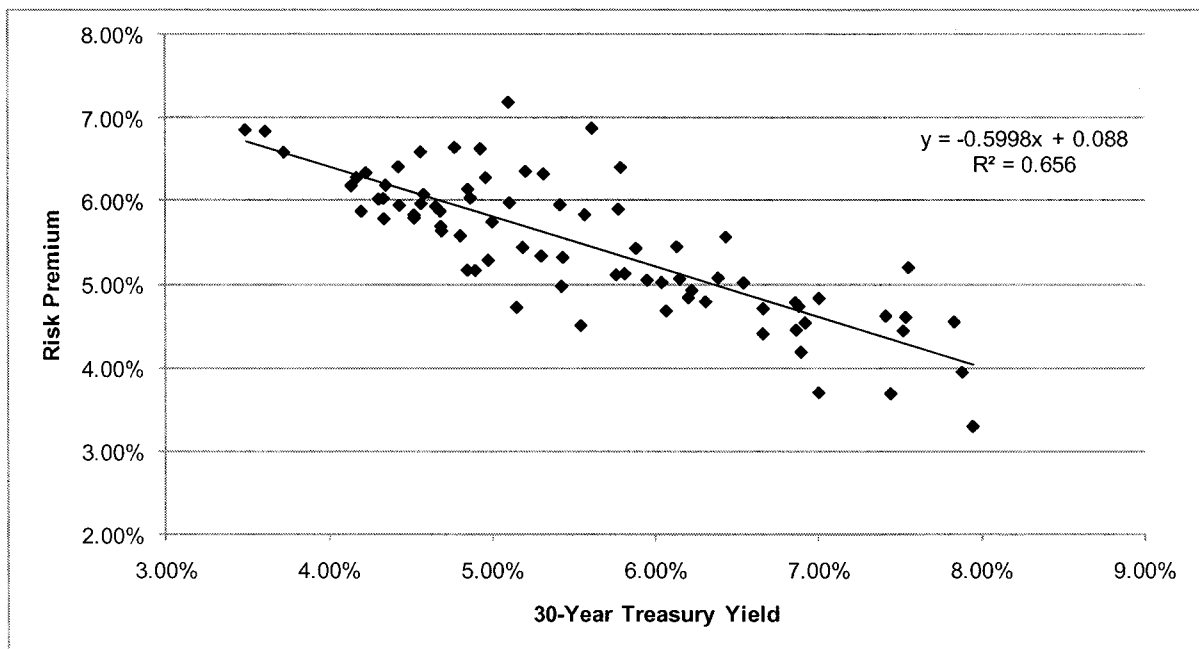
21 a = Intercept term

22 b = Slope term

23 (T) = 30-Year Treasury Bond Yield

1 Data regarding allowed ROEs was derived from 496
 2 electric utility rate cases from January 1992 through May
 3 31, 2011, as reported by Regulatory Research Associates.
 4 The equation's coefficients were significant at the
 5 99.00% confidence interval.⁴⁰

6 **Chart 5: Risk Premium vs. 30-Year Treasury Yield**



7 As shown on Exhibit (D)-5, from January 1992 through
 8 May 31, 2011 the average risk premium was approximately
 9 5.47%, and the average Treasury yield was approximately
 10 5.57%. Based on the regression coefficients provided in
 11 Exhibit (D)-5, however, the risk premium would be 6.20%

⁴⁰ In order to ensure that the regression coefficients were not biased as a result of serially correlated error terms, the equation presented in Exhibit (D)-5 was also estimated using the Prais-Winsten corrective routine. That equation continues to produce a negative slope coefficient and a range of ROE estimates from 10.55 percent based on the 30-day average historical 30-year Treasury yield to 10.99 percent based on the long-term forecast for the 30-year Treasury yield.

1 when using the current 30-day average of the 30-year U.S.
2 Treasury bond yield, resulting in an ROE of 10.54%.
3 Based on the near- and long-term projections of the
4 30-year Treasury bond yields, the resulting ROE is 10.76%
5 and 10.98%, respectively.

6 **V. BUSINESS RISKS**

7 **Q. DO THE MEAN DCF RESULTS FOR THE PROXY GROUP PROVIDE AN**
8 **APPROPRIATE ESTIMATE FOR THE COST OF EQUITY FOR PEPSCO?**

9 A. No, the mean DCF results do not necessarily provide
10 an appropriate estimate of Pepco's Cost of Equity. In my
11 view, there are additional factors that must be taken
12 into consideration when determining where the Company's
13 Cost of Equity falls within the range of results. Those
14 factors include: (1) the regulatory environment in which
15 the Company operates; and (2) the Company's extensive
16 capital investment plan. These risk factors, which I
17 discuss below, should be considered in terms of their
18 overall effect on Pepco's business risk, and, therefore,
19 its Cost of Equity. While I did not include any explicit
20 adjustments to my ROE estimates for these factors, I did
21 take them into consideration when determining where
22 Pepco's ROE falls within my range of analytical results.⁴¹

⁴¹ As discussed later in this Section, I also considered whether the BSA has a measurable effect on the Company's Cost of Equity.

A. Regulatory Risk

Q. PLEASE EXPLAIN HOW THE REGULATORY ENVIRONMENT AFFECTS INVESTORS' RISK ASSESSMENTS.

A. The ratemaking process is premised on the principle that, in order for investors and companies to commit the capital needed to provide safe and reliable utility services, the subject utility must have the opportunity to recover the return of, and the market-required return on, invested capital. Regulatory commissions recognize that because utility operations are capital intensive, regulatory decisions should enable the utility to attract capital at reasonable terms; doing so balances the long-term interests of investors and customers. In that respect, the regulatory environment is one of the most important factors considered in both debt and equity investors' risk assessments.

From the perspective of debt investors, the authorized return should enable the Company to generate the cash flow needed to meet its near-term financial obligations, make the capital investments needed to maintain and expand its system, and maintain sufficient levels of liquidity to fund unexpected events. This financial liquidity must be derived not only from internally generated funds, but also by efficient access

1 to capital markets. Moreover, because fixed income
2 investors have many investment alternatives, even within
3 a given market sector, the Company's financial profile
4 must be adequate on a relative basis to ensure its
5 ability to attract capital under a variety of economic
6 and financial market conditions.

7 From the perspective of equity investors, the
8 authorized return must be adequate to provide a
9 risk-comparable return on the equity portion of the
10 Company's capital investments. Because equity investors
11 are the residual claimants on the Company's cash flows
12 (which is to say that the equity return is subordinate to
13 interest payments), they are particularly concerned with
14 the strength of regulatory support and its effect on
15 future cash flows.

16 The financial community monitors not only the
17 regulatory environment in which utility companies
18 operate, but also the current and expected conditions of
19 the capital markets from which utilities must attract
20 long-term capital. Therefore, it is important for the
21 ROE authorized in this proceeding to consider the capital
22 market conditions with which Pepco must contend, as well
23 as investors' expectations and requirements relating to
24 both risks and returns. In light of recent capital

1 market conditions in general, and the Company's business
2 risks in particular, it is important that Pepco be
3 afforded the opportunity to maintain an adequate
4 financial profile and to earn a reasonable return.

5 **Q. PLEASE EXPLAIN HOW CREDIT RATING AGENCIES CONSIDER**
6 **REGULATORY RISK IN ESTABLISHING A COMPANY'S CREDIT**
7 **RATING.**

8 A. There is little question that rating agencies
9 consider the regulatory environment, including the extent
10 to which the presiding regulatory commission is
11 supportive of issues affecting credit quality, to be an
12 important determinant of the subject company's credit
13 profile. For example, in its assessment of U.S. utility
14 regulatory environments, S&P stated, "we believe the
15 fundamental regulatory environment in the jurisdictions
16 in which a utility operates often influence credit
17 quality the most."⁴²

18 It is important to note that regulatory decisions
19 regarding the ROE and capital structure have direct
20 consequences for the subject utility's internal cash flow
21 generation (sometimes referred to as "Funds Flow from
22 Operations," or "FFO"). Because credit ratings are
23 intended to reflect the ability to meet financial

⁴² Standard & Poor's, *Assessing U.S. Utility Regulatory Environments*,
March 11, 2010, at 2.

1 obligations as they come due, the ability to generate the
2 cash flows required to meet those obligations (and to
3 provide an additional amount for unexpected events) is of
4 critical importance to debt investors. Two of the most
5 important metrics used to assess that ability are the
6 ratios of FFO to debt and FFO to interest expense, both
7 of which are directly affected by regulatory decisions
8 regarding the appropriate rate of return and capital
9 structure.

10 **Q. HAVE THE CREDIT RATINGS AGENCIES ASSESSED SPECIFICALLY**
11 **THE REGULATORY ENVIRONMENT IN THE DISTRICT OF COLUMBIA?**

12 A. Yes. S&P assesses each jurisdiction in the U.S.,
13 and assigns it a ranking on a five grade scale from "most
14 credit supportive" to "least credit supportive." In its
15 most recently published report, S&P assessed the District
16 of Columbia as being "least credit supportive."⁴³ Of the
17 proxy group companies, only Pinnacle West Capital
18 operates in a "least credit supportive" jurisdiction
19 (i.e., Arizona).

20 **Q. WHAT IS YOUR CONCLUSION REGARDING THE EFFECT OF PEPCO'S**
21 **REGULATORY ENVIRONMENT ON ITS ROE?**

22 A. The regulatory environment in which a company
23 operates is of significant importance to investors.

⁴³ Standard & Poor's, *Standard & Poor's Updates its U.S. Utility Regulatory Assessments*, March 12, 2010, at 1.

1 Furthermore, S&P has assessed the District of Columbia as
2 posing greater regulatory risk than the jurisdictions
3 within which the proxy group companies operate,
4 suggesting greater regulatory risk for Pepco than on
5 average for the proxy group.

6 ***B. Capital Expenditures***

7 **Q. PLEASE SUMMARIZE THE COMPANY'S CAPITAL EXPENDITURE PLANS.**

8 A. The Company estimates that from 2011 to 2015 it will
9 invest approximately \$816.7 million in electric
10 distribution infrastructure in the District of Columbia.⁴⁴
11 Those expenditures are to maintain system requirements
12 and to assure reliability.

13 To put those planned investment amounts in
14 perspective, the \$816.7 million in estimated spending
15 represents a 42.88% increase over the previous five years
16 of capital spending (*i.e.*, \$571.6 million in capital
17 expenditures from 2006 to 2010).⁴⁵ In addition, as of
18 December 31, 2010, the Company's 13-month average balance
19 of net property, plant and equipment in District of
20 Columbia was \$1.471 billion.⁴⁶ As such, the five-year
21 investment plan represents an increase of approximately
22 55.53% over the Company's existing net plant.

⁴⁴ See Direct Testimony of Mr. William Gausman, at 9.

⁴⁵ Id. at 8.

⁴⁶ Data provided by Company.

1 Q. HOW IS THE COMPANY'S RISK PROFILE AFFECTED BY THE
2 SUBSTANTIAL INCREASE IN ITS PLANNED CAPITAL EXPENDITURES?

3 A. As with any utility faced with a substantial capital
4 expenditure plan, the Company's risk profile is adversely
5 affected in two significant and related ways: (1) the
6 heightened level of investment increases the risk of
7 under-recovery, or the delayed recovery of the invested
8 capital; and (2) an inadequate authorized return would
9 put downward pressure on key credit metrics.

10 Q. DO CREDIT RATING AGENCIES RECOGNIZE THE RISKS ASSOCIATED
11 WITH INCREASED CAPITAL EXPENDITURES?

12 A. Yes, they do. From a credit perspective, the
13 additional pressure on cash flows associated with high
14 levels of capital expenditures exerts corresponding
15 pressure on credit metrics and, therefore, credit
16 ratings. S&P noted several long term challenges for
17 utilities' financial health including: heavy construction
18 programs to address demand growth, declining capacity
19 margins, an aging infrastructure and regulatory
20 responsiveness to mounting requests for rate increases.
21 S&P further noted that:

22 To sustain their current credit quality in the
23 face of these long-lived challenges, utilities
24 need to have established-and be able to
25 maintain-a firm credit foundation. This will
26 require a strong and effective working

1 relationship among management, regulators, and
2 increasingly legislators and governors, in the
3 planning and execution of strategies. A
4 comprehensive vetting and understanding of the
5 risks associated with the regulatory mechanisms
6 under which the utility will recover its
7 investment, which could include a cash return
8 during construction and timely recognition of
9 volatile costs, will be paramount in preserving
10 creditworthiness.⁴⁷

11 Therefore, to the extent that the Company's current
12 regulatory structure cannot meet the Company's
13 objectives, the Company will face increased recovery risk
14 and thus increased pressure on its credit metrics.

15 **Q. ARE EQUITY INVESTORS ALSO CONCERNED WITH COMPARATIVELY**
16 **HIGH LEVELS OF CAPITAL EXPENDITURES?**

17 A. Yes, equity investors also recognize the pressure on
18 cash flows and earnings associated with relatively high
19 levels of capital expenditures. For example, KeyBanc
20 Capital Markets (KeyBanc) conducts a quarterly review of
21 the electric utility industry. In a recent report,
22 KeyBanc noted that:

23 Although capital markets have improved since
24 early 2009, liquidity and capital costs remain
25 a concern, as costs for credit have generally
26 become more expensive and available durations
27 have shrunk. Higher interest costs will likely
28 continue to pressure earnings until regulatory
29 lag is better addressed.

30 ***

⁴⁷ Standard & Poor's RatingsDirect, *Industry Report Card: Utility Sectors In the Americas Remain Stable, While Challenges Beset European, Australian, and New Zealand Counterparts*, June 27, 2008, at 4.

1 Credit and liquidity concerns have driven many
2 companies to revisit capital spending plans and
3 reassess operational efficiencies.⁴⁸

4 **Q. WILL THE COMPANY NEED CONTINUED ACCESS TO THE CAPITAL**
5 **MARKETS IN ORDER TO FINANCE ITS CAPITAL EXPENDITURE PLAN?**

6 A. Yes. When the level of capital expenditures
7 outpaces the growth in internally generated cash, there
8 is increasing pressure to access the external capital
9 markets. Given the size and long-term nature of the
10 anticipated capital expenditures, the Company will
11 require continued access to external capital, at
12 reasonable terms, in order to finance its capital
13 expenditure plan. As noted throughout my testimony,
14 Pepco's ability to generate internal cash flow and access
15 the capital markets will be directly affected by the
16 Commission's order in this proceeding.

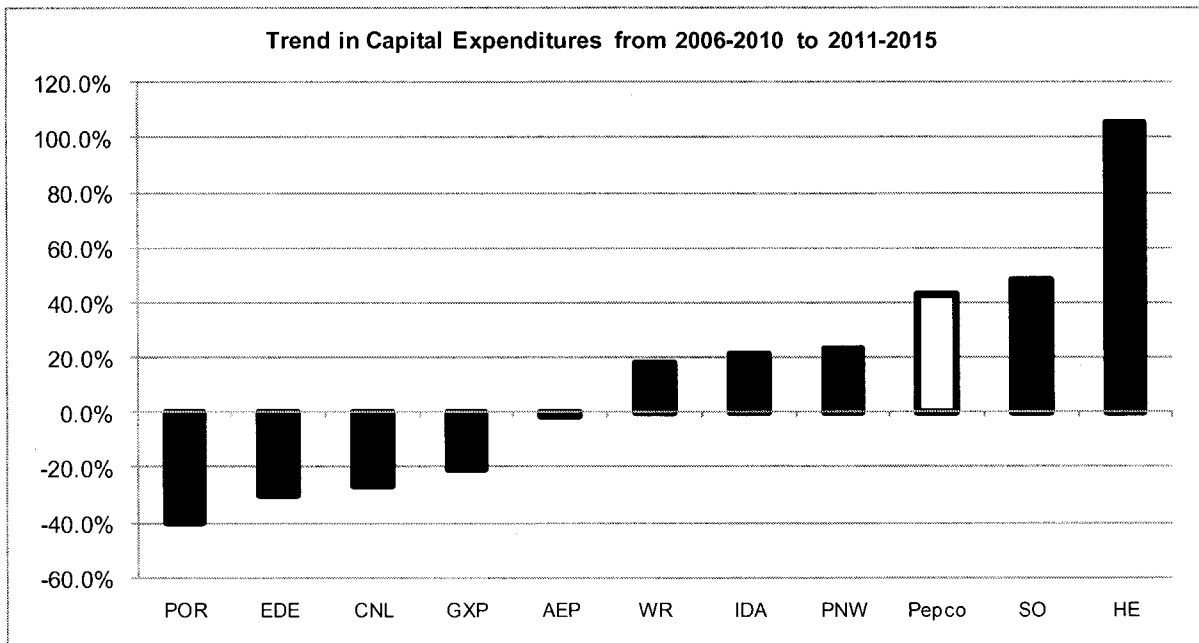
17 **Q. HAVE YOU COMPARED THE TREND IN PEPCO'S CAPITAL**
18 **EXPENDITURES TO THE PROXY GROUP COMPANIES?**

19 A. Yes, I have compared the actual capital expenditures
20 from 2006-2010 to the expected capital expenditures from
21 2011-2015 for Pepco and each of the proxy group
22 companies. It is clear from this analysis that Pepco's
23 capital expenditure program is accelerating more rapidly
24 than the average of the proxy group companies. Chart 6

⁴⁸ KeyBanc Capital Markets Inc., *Electric Utilities Quarterly 4Q10*,
March 2011, at 7.

(below), (see also Exhibit (D)-6) demonstrates that Pepco's capital expenditures over the next five years will grow by approximately 42.88%. By contrast, five of the proxy group companies are projected to have a decrease in spending, while three others are projected to increase capital spending by less than 25.00% during 2011-2015, as compared to their prior five year history. The average projected increase in capital spending for the proxy group is 9.70%, or 33.18% less than Pepco's estimated increase in spending.

Chart 6: Comparison of Trend in Capital Expenditures⁴⁹



⁴⁹ Source: Proxy group estimates based on Value Line data. Pepco data provided by the Company. The capital expenditure estimate for Empire District Electric excludes expected restoration costs required within its service territory as a result of the tornado damage suffered in May 2011.

1 Q. WHAT ARE YOUR CONCLUSIONS REGARDING THE EFFECT OF THE
2 COMPANY'S CAPITAL INVESTMENT PLAN ON ITS RISK PROFILE AND
3 COST OF CAPITAL?

4 A. It is clear that on a relative basis, the Company's
5 capital expenditure program is significant. It also is
6 clear that the financial community recognizes the
7 additional risks associated with substantial capital
8 expenditures and that those risks are reflected in market
9 valuation multiples. In my view, these factors suggest a
10 high level of risk relative to the proxy group.

11 *C. Flotation Cost Adjustment*

12 Q. WHAT ARE FLOTATION COSTS?

13 A. Flotation costs are the costs associated with the
14 sale of new issues of common stock. These costs include
15 out-of-pocket expenditures for preparation, filing,
16 underwriting, and other issuance costs.

17 Q. HAVE YOU INCORPORATED A FLOTATION COST ADJUSTMENT INTO
18 YOUR ROE RECOMMENDATION?

19 A. No, I have not. As discussed in Appendix A, while
20 it is my opinion that the appropriate manner in which to
21 reflect flotation costs is through an adjustment to the
22 allowed ROE, I understand that it is the Commission's
23 traditional practice to treat flotation costs as an

1 expense item in utilities' cost of service.⁵⁰ However, if
2 the Commission rejects flotation costs as an expense item
3 of cost of service, I believe it is appropriate to
4 reflect a flotation cost adjustment in the authorized ROE
5 (as calculated in Appendix A and Exhibit (D)-7).

6 ***D. Effect of the Company's Bill Stabilization Adjustment***
7 ***on Cost of Equity***

8 **Q. PLEASE DESCRIBE THE COMPANY'S BILL STABILIZATION**
9 **ADJUSTMENT.**

10 A. The BSA, which decouples the Company's revenue from
11 kilowatt-hour sales, tracks monthly under or
12 over-collections in the Company's authorized revenue
13 requirement by customer class and adjusts the customer's
14 distribution rate for these historical variations in
15 revenue. The BSA credit or surcharge is capped at 10.00%
16 of the test-year average base rate for the month. If the
17 surcharge or credit exceeds the cap, the difference is
18 carried over to the next month. The Commission notes that
19 the BSA is "intended to account for changes in usage due

⁵⁰ See, Formal Case No. 1076, *In the Matter of the Application of the Potomac Electric Power Company for Authority to Increase Existing Retail Rates and Charges for Electric Distribution Service*, Order No. 15710, March 2, 2010, at 25.

1 to variations in weather, customer response to price
2 increases or energy-efficiency programs."⁵¹

3 **Q. HAVE YOU REVIEWED THE COMMISSION'S POSITION AS TO THE**
4 **EFFECT OF THE BSA ON THE COMPANY'S ROE IN PRIOR ORDERS?**

5 A. Yes, I have. I understand that when the Commission
6 approved the BSA in Case No. 15556, it established a 50
7 basis point reduction in the ROE, stating that
8 "implementation of the BSA insulates Pepco from losing
9 revenues which, in turn, lowers the Company's business
10 risk and results in a lower cost of capital".⁵² In the
11 Company's recent rate proceeding, the Commission
12 reaffirmed the 50 basis point reduction to the ROE.⁵³

13 **Q. DO YOU AGREE THAT THE ROE SHOULD BE ADJUSTED 50 BASIS**
14 **POINTS TO REFLECT A CHANGE IN THE COMPANY'S RISK PROFILE**
15 **AS A RESULT OF THE IMPLEMENTATION OF THE BSA?**

16 A. No, I do not. As noted above, the Commission
17 established an adjustment to the ROE based on the risk-
18 mitigating properties of the BSA mechanism. I
19 respectfully disagree with the Commission's use of that

⁵¹ Formal Case No. 1053, *In the Matter of the Application of Potomac Electric Power Company for Authority to Increase Existing Retail Rates and Charges for Electric Distribution Service, Phase II*, Order No. 15556, September 28, 2009, at 1.

⁵² *Id.* at 9.

⁵³ Formal Case No. 1076, *In the Matter of the Application of the Potomac Electric Power Company for Authority to Increase Existing Retail Rates and Charges for Electric Distribution Service*, Order No. 15710, March 2, 2010, at 33.

1 criterion. In my view, for the purpose of estimating the
2 Cost of Equity the salient analytical issue is whether
3 the Company is so less risky than its peers as a direct
4 result of the BSA that investors would specifically and
5 measurably reduce their return requirement. The fact
6 that the Company's revenues may be affected by the BSA
7 does not bear on to the estimated Cost of Equity unless
8 it can be demonstrated that (1) the Company is materially
9 less risky than the proxy group by virtue of the BSA, and
10 (2) the financial markets react to the incremental effect
11 of the mechanism.

12 **Q. HOW COMMON ARE REVENUE STABILIZATION MECHANISMS SUCH AS**
13 **THE BSA AMONG ELECTRIC UTILITIES?**

14 A. There is little question that revenue stabilization
15 structures are becoming increasingly common. The
16 increased interest in such mechanisms has generally
17 resulted from the growing cost of maintaining system
18 reliability, coupled with the flat or declining volume
19 brought on by energy efficiency and relatively slow
20 economic growth. The Commission acknowledged this in its
21 Order approving Pepco's BSA, stating:

22 A number of states have recently considered the
23 decoupling issue as a means of removing
24 disincentives for utilities to invest in energy
25 efficiency measures. The approaches vary but,
26 in general, the mechanism insulates the

1 utility's revenue from such factors as changes
2 in sales volume, weather and economic
3 activity.⁵⁴

4 According to an April 2011 report published by
5 Regulatory Research Associates (RRA), revenue decoupling
6 has been implemented by electric utilities in 18 states.⁵⁵

7 **Q. ARE REVENUE STABILIZATION MECHANISMS COMMON AMONG THE**
8 **PROXY GROUP COMPANIES?**

9 A. Yes, they are. Exhibit (D)-8 provides a summary of
10 revenue stabilization mechanisms and cost trackers
11 currently in effect at each electric utility subsidiary
12 of the proxy group companies. As Exhibit (D)-8
13 demonstrates, there are a substantial number of recovery
14 mechanisms in place at the proxy companies. By
15 extension, Exhibit (D)-8 demonstrates that the BSA only
16 increases the degree to which Pepco is comparable to the
17 proxy group in terms of its regulatory treatment.

18 Moreover, public policy has placed an increasing
19 focus on alternative regulation and revenue stabilization
20 structures, and as such, base rate proceedings are not
21 the only forum in which investors and analysts are made

⁵⁴ Formal Case No. 1053, *In the Matter of the Application of Potomac Electric Power Company for Authority to Increase Existing Retail Rates and Charges for Electric Distribution Service, Phase II*, Order No. 15556, September 28, 2009, at 7.

⁵⁵ Regulatory Research Associates, *Decoupling Mechanisms/Straight-Fixed-Variable Rate Design: A State-By-State Overview*, April 5, 2011, at 2.

1 aware of the issue. In that regard, the American
2 Recovery and Reinvestment Act of 2009 endorses the
3 implementation of such structures for energy efficiency
4 and conservation purposes:

5 The applicable State regulatory authority will
6 seek to implement, in appropriate proceedings
7 for each electric and gas utility, with respect
8 to which the State regulatory authority has
9 ratemaking authority, a general policy that
10 ensures that utility financial incentives are
11 aligned with helping customers use energy more
12 efficiently and that provide timely cost
13 recovery and a timely earnings opportunity for
14 utilities associated with cost-effective
15 measurable and verifiable efficiency savings,
16 in a way that sustains or enhances utility
17 customers' incentives to use energy more
18 efficiently.⁵⁶

19 Consequently, the implementation of alternative
20 regulation mechanisms has become an increasingly visible
21 issue to investors.

22 **Q. DOES THE FINANCIAL COMMUNITY RECOGNIZE THE BENEFIT OF**
23 **REVENUE STABILIZATION MECHANISMS?**

24 **A.** Yes. Equity and credit analysts often consider
25 revenue stabilization mechanisms as a component in their
26 overall risk assessment of a subject company. For
27 instance, Macquarie Equities Research noted in regards to
28 Hawaiian Electric:

29 Decoupling decision still matters most. We
30 continue to believe the most important event

⁵⁶ S. 1--111th Congress: American Recovery and Reinvestment Act of
2009, at 33.

1 for HE will be the Hawaii PUC's final decision
2 on decoupling.⁵⁷

3 J.P Morgan stated the following regarding regulatory
4 risk and decoupling for Portland General Electric:

5 We believe its yield is attractive on an
6 absolute basis; and believe it offers investors
7 a relatively low risk investment opportunity
8 given that the company faces limited regulatory
9 risk in the near term, has been granted a
10 decoupling mechanism that should help insulate
11 it from fluctuations in retail power demand
12 over the next few years, and has completed a
13 material equity offer to bolster its financial
14 strength.⁵⁸

15 In addition, Fitch Ratings, in a report on Westar,
16 Inc., noted:

17 The ratings and Positive Rating Outlook on
18 Westar and KGE primarily reflect recent
19 regulatory decisions and cost-recovery
20 mechanisms that will allow the utility to earn
21 a reasonable return on invested capital and
22 limit the negative effects of commodity price
23 volatility.⁵⁹

24 In recent years the KCC has implemented several
25 cost-recovery mechanisms that facilitate
26 recovery of fuel and purchase power costs and
27 environmental and transmission investments
28 outside of GRC proceedings. These rate riders
29 have reduced regulatory lag and provided
30 stability to the financial profile. The retail
31 energy cost adjustment (RECA) adjusts fuel and
32 purchased power prices on a quarterly basis and
33 settles the associated accruals and deferrals
34 annually, largely mitigating the negative
35 effects of fuel and power price volatility.

⁵⁷ *Hawaiian Electric Industries*, Macquarie Equities Research, May 12, 2010, at 1.

⁵⁸ *Portland General Electric Co.*, J.P. Morgan, July 22, 2009, at 2.

⁵⁹ *Westar Energy Inc.*, Fitch Ratings, June 1, 2010, at 1.

1 The environmental cost recovery rider (ECRR)
2 adjusts retail rates annually to reflect
3 capital costs for emission controls, which are
4 expected to account for 40% of consolidated
5 capital expenditures during the 2010-2012 time
6 period. Other cost-recovery mechanisms
7 authorized by the KCC include a transmission
8 cost-recovery rider for retail rates and a
9 pension and other post-employment benefits
10 expense tracker. In addition, the Federal
11 Energy Regulatory Commission (FERC) allows for
12 recovery of transmission capital expenditures
13 and cost of service through a formula rate that
14 is updated annually.⁶⁰

15 Based on those comments, it is reasonable to assume
16 that the effect, if any, of revenue stabilization
17 mechanisms already are reflected in the proxy companies'
18 market prices.

19 **Q. HAVE YOU REVIEWED CASE MATERIALS FROM PROCEEDINGS IN**
20 **OTHER JURISDICTIONS IN WHICH DECOUPLING MECHANISMS WERE**
21 **APPROVED?**

22 **A.** Yes. I have surveyed rate proceedings in which
23 decoupling mechanisms were authorized in order to
24 determine the frequency and extent to which the ROE
25 authorized in those proceedings was adjusted as a direct
26 consequence of the decoupling mechanisms. Exhibit (D)-9
27 summarizes the cases that were included in my review. As
28 shown in that Exhibit, I reviewed the decisions in 35
29 electric utility rate proceedings, all of which having

⁶⁰ Id.

1 adopted revenue decoupling since July, 2007. I reviewed
2 each of the Orders from those cases to find what, if any,
3 adjustment was made to the authorized ROE specifically as
4 a result of the adoption of the decoupling mechanism.

5 **Q. WHAT DID THAT ANALYSIS REVEAL?**

6 A. My review found that in the majority of cases,
7 utility commissions have not made explicit adjustments to
8 the authorized ROEs in response to the implementation of
9 decoupling mechanisms. Of the 35 electric utility
10 proceedings that I reviewed for my analysis, 18 of them
11 had no change to their authorized ROE as a result of the
12 implementation of a decoupling mechanism. Of the
13 remaining 17 proceedings in which a utility commission
14 did order an adjustment to the ROE specifically because
15 of the decoupling implementation, six had no defined
16 adjustment. Finally, of the eleven cases in which there
17 was an explicit adjustment to the ROE, seven were 50
18 basis point adjustments authorized by either the District
19 of Columbia or Maryland. The remaining four cases
20 resulted in adjustments of 10 to 25 basis points.⁶¹

⁶¹ As shown in Exhibit (D)-9, the Oregon Public Service Commission authorized a 10 basis point adjustment in two cases, the New York Public Service Commission authorized a 10 basis point adjustment in one case, and the Montana Public Service Commission authorized a 25 basis point adjustment in one case.

1 Q. IN ITS MOST RECENT ORDER FOR PEPCO, THE COMMISSION STATED
2 THAT, "IT HAS NOT BEEN SHOWN THAT MECHANISMS IN [OTHER]
3 JURISDICTIONS ARE COMPARABLE TO PEPCO'S BSA OR THAT THE
4 OVERALL FOCUS AND CONCERNS IN THOSE PROCEEDINGS WERE
5 SIMILAR TO THOSE OF THIS COMMISSION."⁶² WHAT IS YOUR
6 RESPONSE TO THAT POINT?

7 A. While I agree that the various mechanisms may differ
8 in certain respects, the intent of such rate structures
9 is to address the erosion in revenue associated with
10 declining use. From an investor's perspective, the
11 principle issue is whether the stabilizing effect of the
12 mechanism so significantly differentiates the subject
13 company from its peers that the required return would be
14 specifically and substantially reduced as a direct result
15 of the structure. The fact that more than half of
16 utility commission decisions did not make a specific
17 adjustment to the authorized ROE is, in my view,
18 information that is available to, and considered by
19 investors. I also note that, excluding the adjustments
20 that have been authorized by the Maryland Public Service
21 Commission and this Commission, the most prevalent
22 adjustment for the implementation of a decoupling

⁶² Formal Case No. 1076, *In the Matter of the Application of the Potomac Electric Power Company for Authority to Increase Existing Retail Rates and Charges for Electric Distribution Service*, Order No. 15710, March 2, 2010, at 33.

1 mechanism is 10 basis points. Moreover, as noted
2 earlier, investors consider the range of revenue
3 stabilization and cost recovery mechanisms in place at
4 utility companies; they would not be inclined to consider
5 one mechanism in isolation. Consequently, I respectfully
6 disagree with the conclusion that differences in
7 structures justify a 50 basis point reduction to the
8 authorized ROE.

9 **Q. WHAT IS YOUR CONCLUSION REGARDING THE EFFECT OF THE BSA**
10 **ON THE COMPANY'S COST OF EQUITY?**

11 A. As noted above, revenue stabilization structures are
12 becoming increasingly common for many companies facing an
13 inability to recover prudently incurred fixed costs.
14 Furthermore, investors are expecting that some form of
15 stabilization will be implemented in utility rate
16 regulation. In addition, the proxy group companies have
17 implemented many forms of rate stabilization mechanisms
18 that provide for risk mitigation similar to that which is
19 provided by the BSA. Moreover, there is no conclusive
20 evidence of which I am aware indicating that companies
21 that have implemented such structures either have lower
22 required ROEs (or have significantly different market
23 valuations). I therefore conclude that the BSA has no
24 effect on my recommended ROE.

VI. CAPITAL STRUCTURE

Q. WHAT IS THE COMPANY'S PROJECTED CAPITAL STRUCTURE?

A. As described in the Direct Testimony of Company Witness McGowan, the Company's proposed capital structure consists of 49.23% common equity and 50.77% long-term debt.

Q. PLEASE DISCUSS YOUR ANALYSIS OF THE CAPITAL STRUCTURES OF THE PROXY GROUP COMPANIES.

A. My analysis of the actual proxy group capital structures is provided in Exhibit (D)-10. As shown in that Exhibit, I calculated the mean of the proportions of common equity and long-term debt over the most recent eight quarters⁶³ for the utility operating companies held by each of the proxy group companies.

Q. PLEASE SUMMARIZE THE RESULTS OF YOUR ANALYSIS.

A. As shown in Exhibit (D)-10, the Company's proposed capital structure of 49.23% common equity and 50.77% long-term debt is within the range of the capital structures in place at the utility operating companies held within my proxy group.

⁶³ In this analysis, I calculated the average capital structure using the quarterly capital structures reported for the proxy group companies for the period from June 2009 through March 2011.

1 Q. WHAT IS YOUR CONCLUSION REGARDING AN APPROPRIATE CAPITAL
2 STRUCTURE FOR PEPCO?

3 A. Considering the actual capital structures of the
4 proxy group and the Company's extensive capital
5 investment program, I believe that the Company's proposed
6 equity ratio of 49.23% is reasonable, if not
7 conservative.

8 Q. WILL THE CAPITAL STRUCTURE AND ROE AUTHORIZED IN THIS
9 PROCEEDING AFFECT THE COMPANY'S ABILITY TO COMPLETE ITS
10 CAPITAL EXPENDITURE PLAN?

11 A. Yes, I believe so. The level of earnings authorized
12 by the Commission directly affects the Company's ability
13 to fund capital investment with internally generated
14 funds; and both lenders and equity investors expect a
15 significant portion of on-going capital investments to be
16 financed with internally generated funds. The need to
17 generate funds internally also is important in light of
18 the constrained, volatile, and expensive capital market
19 conditions.

20 It also is important to realize that investors weigh
21 a given utility's authorized ROE in the context of the
22 nature of its expected capital investments. Because a
23 utility's investment horizon is very long, investors
24 require the assurance of a sufficiently high return to

1 satisfy the long-run financing requirements of the assets
2 it puts into service. Those assurances, which often are
3 measured by the relationship between internally generated
4 cash flows and debt (or interest expense), depend quite
5 heavily on the capital structure. As a consequence, both
6 the ROE and capital structure are very important to both
7 debt and equity investors. Given the capital market
8 conditions and the Company's significant financing
9 requirements, the authorized ROE and capital structure
10 are extremely important considerations in this
11 proceeding.

12 **VII. SUMMARY AND CONCLUSIONS**

13 **Q. PLEASE SUMMARIZE YOUR RECOMMENDED RETURN ON COMMON EQUITY**
14 **CALCULATIONS, TAKING INTO CONSIDERATION THE BUSINESS RISK**
15 **ISSUES DISCUSSED ABOVE.**

16 **A.** Based on the results presented in Table 7, I believe
17 that an ROE in the range of 10.50% to 11.25 % reasonably
18 represents the range of the required Cost of Equity for
19 Pepco in today's capital markets. I further believe that
20 within that range, an ROE of 10.75% is reasonable.

21 In addition, while I understand the Commission's
22 prior position regarding the effect of the Company's BSA
23 on its Cost of Equity, I do not believe that equity
24 investors consider that mechanism to be so risk

1 mitigating relative to its peers that they would reduce
2 their equity return requirements by as much as 50 basis
3 points. Consequently, I have not reduced my recommended
4 ROE as a result of the BSA. Finally, I believe that my
5 recommended return balances the interests of customers
6 and shareholders by enabling the Company to maintain its
7 financial integrity and thus its ability to attract
8 capital at reasonable rates.

1

Table 7: Mean ROE Estimates

	Mean Low Results	Mean Results	Mean High Results
Constant Growth DCF Results			
30-day Average Stock Price	9.58%	10.71%	11.87%
90-day Average Stock Price	9.72%	10.85%	12.01%
180-day Average Stock Price	9.83%	10.96%	12.12%
Ex-Ante CAPM Results			
	Sharpe Ratio Derived Market Risk Premium	DCF Derived Market Risk Premium	
	Twelve-month Beta Coefficient		
Current 30-Year Treasury Yield (4.34%)	9.62%	10.44%	
Projected 30-Year Treasury Yield (4.88%)	10.17%	10.99%	
	Average Bloomberg and Valueline Beta Coefficient		
Current 30-Year Treasury Yield (4.34%)	9.68%	10.50%	
Projected 30-Year Treasury Yield (4.88%)	10.22%	11.05%	
Bond Yield Plus Risk Premium Analysis			
	Current (4.34%)	Near-Term Projected (4.88%)	Long-Term Projected (5.45%)
30-Year Treasury Yield	10.54	10.76	10.98

2 Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

3 A. Yes, it does.

HEVERT APPENDIX A

Robert B. Hevert, CFA
President

Mr. Hevert is an economic and financial consultant with broad experience in the energy industry. He has an extensive background in the areas of corporate strategic planning, energy market assessment, corporate finance, mergers, and acquisitions, asset-based transactions, asset and business unit valuation, market entry strategies, strategic alliances, project development, feasibility and due diligence analyses. Mr. Hevert has significant management experience with both operating and professional services companies.

REPRESENTATIVE PROJECT EXPERIENCE

Financial and Economic Advisory Services

Retained by numerous leading energy companies and financial institutions throughout North America to provide services relating to the strategic evaluation, acquisition, sale or development of a variety of regulated and non-regulated enterprises. Specific services have included: developing strategic and financial analyses and managing multi-faceted due diligence reviews of proposed corporate M&A counter-parties; developing, screening and recommending potential M&A transactions and facilitating discussions between senior utility executives regarding transaction strategy and structure; performing valuation analyses and financial due diligence reviews of electric generation projects, retail marketing companies, and wholesale trading entities in support of significant M&A transactions.

Specific divestiture-related services have included advising both buy and sell-side clients in transactions for physical and contractual electric generation resources. Sell-side services have included: development and implementation of key aspects of asset divestiture programs such as marketing, offering memorandum development, development of transaction terms and conditions, bid process management, bid evaluation, negotiations, and regulatory approval process. Buy-side services have included comprehensive asset screening, selection, valuation and due diligence reviews. Both buy and sell-side services have included the use of sophisticated asset valuation techniques, and the development and delivery of fairness opinions.

Specific corporate finance experience while a Vice President with Bay State Gas included: negotiation, placement and closing of both private and public long-term debt, preferred and common equity; structured and project financing; corporate cash management; financial analysis, planning and forecasting; and various aspects of investor relations.

Representative non-confidential clients have included:

- Conectiv generation asset divestiture
- Eastern Utilities Associates (prior to acquisition by National Grid, PLC) generation asset divestiture
- Niagara Mohawk – sale of Niagara Mohawk Energy
- Potomac Electric Company generation asset divestiture

Representative confidential engagements have included:

- Buy-side valuation and assessment of merchant generation assets in Midwestern U.S.
- Buy-side due diligence and valuation of wholesale energy marketing companies in Eastern and Midwestern U.S.
- Buy-side due diligence of natural gas distribution assets in Northeastern U.S.
- Financial feasibility study of natural gas pipeline in upper Midwestern U.S.

- Financial valuation of natural gas pipeline in Southwestern U.S.

Regulatory Analysis and Ratemaking

On behalf of electric, natural gas and combination utilities throughout North America, provided services relating to energy industry restructuring including merchant function exit, residual energy supply obligations, and stranded cost assessment and recovery. Also performed rate of return and cost of service analyses for municipally owned gas and electric utilities. Specific services provided include: performing strategic review and development of merchant function exit strategies including analysis of provider of last resort obligations in both electric and gas markets; and developing value optimizing strategies for physical generation assets.

Representative engagements have included:

- Performing rate of return analyses for use in cost of service analyses on behalf of municipally owned gas and electric utilities in the Southeastern and Midwestern U.S.
- Developing merchant function exit strategies for Northeastern U.S. natural gas distribution companies
- Developing regulatory and ratemaking strategy for mergers including several Northeastern natural gas distribution companies

Litigation Support and Expert Testimony

Provided expert testimony and support of litigation in various regulatory proceedings on a variety of energy and economic issues including the proposed transfer of power purchase agreements, procurement of residual service electric supply, the legal separation of generation assets, and specific financing transactions. Services provided also included collaborating with counsel, business and technical staff to develop litigation strategies, preparing and reviewing discovery and briefing materials, preparing presentation materials and participating in technical sessions with regulators and intervenors.

Energy Market Assessment

Retained by numerous leading energy companies and financial institutions nationwide to manage or provide assessments of regional energy markets throughout the U.S. and Canada. Such assessments have included development of electric and natural gas price forecasts, analysis of generation project entry and exit scenarios, assessment of natural gas and electric transmission infrastructure, market structure and regulatory situation analysis, and assessment of competitive position. Market assessment engagements typically have been used as integral elements of business unit or asset-specific strategic plans or valuation analyses.

Representative engagements have included:

- Managing assessments of the NYPOOL, NEPOOL and PJM markets for major North American energy companies considering entering or expanding their presence in those markets
- Assessment of ECAR, MAPP, MAIN and SPP markets for a large U.S. integrated utility considering acquisition of additional electric generation assets
- Assessment of natural gas pipeline and storage capacity in the SERC and FRCC markets for a major international energy company

Resource Procurement, Contracting and Analysis

Assisted various clients in evaluating alternatives for acquiring fuel and power supplies, including the development and negotiation of energy contracts and tolling agreements. Assignments also have included developing generation resource optimization strategies. Provided advice and analyses of transition service power supply contracts in the context of both physical and contractual generation resource divestiture transactions.

Business Strategy and Operations

Retained by numerous leading North American energy companies and financial institutions nationwide to provide services relating to the development of strategic plans and planning processes for both regulated and non-regulated enterprises. Specific services provided include: developing and implementing electric generation strategies and business process redesign initiatives; developing market entry strategies for retail and wholesale businesses including assessment of asset-based marketing and trading strategies; and facilitating executive level strategic planning retreats. As Vice President, Energy Ventures, of Bay State was responsible for the company's strategic planning and business development processes, played an integral role in developing the company's non-regulated marketing affiliate, EnergyUSA, and managed the company's non-regulated investments, partnerships and strategic alliances.

Representative engagements have included:

- Developing and facilitating executive level strategic planning retreats for Northeastern natural gas distribution companies
- Developing organization and business process redesign plans for municipally owned gas/electric/water utility in the Southeastern U.S.
- Reviewing and revising corporate merchant generation business plans for Canadian and U.S. integrated utilities
- Advising client personnel in development of business unit level strategic plans for various natural gas distribution companies

PROFESSIONAL HISTORY

Concentric Energy Advisors, Inc. (2002 – Present)

President

Navigant Consulting, Inc. (1997 – 2001)

Managing Director (2000 – 2001)

Director (1998 – 2000)

Vice President, REED Consulting Group (1997 – 1998)

REED Consulting Group (1997)

Vice President

Bay State Gas Company (1987 – 1997)

Vice President, Energy Ventures and Assistant Treasurer

Boston College (1986 – 1987)

Financial Analyst

General Telephone Company of the South (1984 – 1986)

Revenue Requirements Analyst

EDUCATION

M.B.A., University of Massachusetts at Amherst, 1984

B.S., University of Delaware, 1982

DESIGNATIONS AND PROFESSIONAL AFFILIATIONS

Chartered Financial Analyst, 1991
Association for Investment Management and Research
Boston Security Analyst Society

PUBLICATIONS/PRESENTATIONS

Has made numerous presentations throughout the United States and Canada on several topics, including:

- Generation Asset Valuation and the Use of Real Options
 - Retail and Wholesale Market Entry Strategies
 - The Use Strategic Alliances in Restructured Energy Markets
 - Gas Supply and Pipeline Infrastructure in the Northeast Energy Markets
 - Nuclear Asset Valuation and the Divestiture Process
-

AVAILABLE UPON REQUEST

Extensive client and project listings, and specific references.

SPONSOR	DATE	CASE/APPLICANT	DOCKET No.	SUBJECT
Arizona Corporation Commission				
Southwest Gas Corporation	11/10	Southwest Gas Corporation	Docket No. G-01551A-10-0458	Return on Equity
Arkansas Public Service Commission				
CenterPoint Energy Resources Corp. D/B/A CenterPoint Energy Arkansas Gas	01/07	CenterPoint Energy Resources Corp. D/B/A CenterPoint Energy Arkansas Gas	Docket No. 06-161-U	Return on Equity
Colorado Public Utilities Commission				
Xcel Energy, Inc.	12/10	Public Service Company of Colorado	Docket No. 10AL-963G	Return on Equity (electric)
Atmos Energy Corporation	07/09	Atmos Energy Colorado-Kansas Division	Docket No. 09AL-507G	Return on Equity (gas)
Xcel Energy, Inc.	12/06	Public Service Company of Colorado	Docket No. 06S-656G	Return on Equity (gas)
Xcel Energy, Inc.	04/06	Public Service Company of Colorado	Docket No. 06S-234EG	Return on Equity (electric)
Xcel Energy, Inc.	08/05	Public Service Company of Colorado	Docket No. 05S-369ST	Return on Equity (steam)
Xcel Energy, Inc.	05/05	Public Service Company of Colorado	Docket No. 05S-264G	Return on Equity (gas)
Connecticut Department of Public Utility Control				
Southern Connecticut Gas Company	09/08	Southern Connecticut Gas Company	Docket No. 08-08-17	Return on Equity
Southern Connecticut Gas Company	12/07	Southern Connecticut Gas Company	Docket No. 05-03-17PH02	Return on Equity
Connecticut Natural Gas Corporation	12/07	Connecticut Natural Gas Corporation	Docket No. 06-03-04PH02	Return on Equity

SPONSOR	DATE	CASE/APPLICANT	DOCKET NO.	SUBJECT
Federal Energy Regulatory Commission				
Public Service Company of New Mexico	10/10	Public Service Company of New Mexico	Docket No. ER11-1915-000	Return on Equity
Portland Natural Gas Transmission System	05/10	Portland Natural Gas Transmission System	Docket No. RP10-729-000	Return on Equity
Florida Gas Transmission Company, LLC	10/09	Florida Gas Transmission Company, LLC	Docket No. RP10-21-000	Return on Equity
Maritimes and Northeast Pipeline, LLC	07/09	Maritimes and Northeast Pipeline, LLC	Docket No. RP09-809-000	Return on Equity
Spectra Energy	02/08	Saltville Gas Storage	Docket No. RP08-257-000	Return on Equity
Panhandle Energy Pipelines	08/07	Panhandle Energy Pipelines	Docket No. PL07-2-000	Response to draft policy statement regarding inclusion of MLPs in proxy groups for determination of gas pipeline ROEs
Southwest Gas Storage Company	08/07	Southwest Gas Storage Company	Docket No. RP07-541-000	Return on Equity
Southwest Gas Storage Company	06/07	Southwest Gas Storage Company	Docket No. RP07-34-000	Return on Equity
Sea Robin Pipeline LLC	06/07	Sea Robin Pipeline LLC	Docket No. RP07-513-000	Return on Equity
Transwestern Pipeline Company	09/06	Transwestern Pipeline Company	Docket No. RP06-614-000	Return on Equity
GPU International and Aquila	11/00	GPU International	Docket No. EC01-24-000	Market Power Study
Georgia Public Service Commission				
Atlanta Gas Light Company	05/10	Atlanta Gas Light Company	Docket No. 31647-U	Return on Equity
Illinois Commerce Commission				
Ameren Illinois Company d/b/a Ameren Illinois	02/11	Ameren Illinois Company d/b/a Ameren Illinois	Docket No. 11-0279	Return on Equity (electric)
Ameren Illinois Company d/b/a Ameren Illinois	02/11	Ameren Illinois Company d/b/a Ameren Illinois	Docket No. 11-0282	Return on Equity (gas)

SPONSOR	DATE	CASE/APPLICANT	DOCKET No.	SUBJECT
Maryland Public Service Commission				
Delmarva Power & Light Company	12/10	Delmarva Power & Light	Case No. 9249	Return on Equity
Massachusetts Department of Public Utilities				
National Grid	08/09	Massachusetts Electric Company d/b/a National Grid	DPU 09-39	Revenue Decoupling and Return on Equity
National Grid	08/09	Massachusetts Electric Company and Nantucket Electric Company d/b/a National Grid	DPU 09-38	Return on Equity – Solar Generation
Bay State Gas Company	04/09	Bay State Gas Company	DTE 09-30	Return on Equity
NSTAR Electric	09/04	NSTAR Electric	DTE 04-85	Divestiture of Power Purchase Agreement
NSTAR Electric	08/04	NSTAR Electric	DTE 04-78	Divestiture of Power Purchase Agreement
NSTAR Electric	07/04	NSTAR Electric	DTE 04-68	Divestiture of Power Purchase Agreement
NSTAR Electric	07/04	NSTAR Electric	DTE 04-61	Divestiture of Power Purchase Agreement
NSTAR Electric	06/04	NSTAR Electric	DTE 04-60	Divestiture of Power Purchase Agreement
Unitil Corporation	01/04	Fitchburg Gas and Electric	DTE 03-52	Integrated Resource Plan; Gas Demand Forecast
Minnesota Public Utilities Commission				
Otter Tail Power Corporation	04/10	Otter Tail Power Company	Docket No. E-017/GR- 10-239	Return on Equity
Minnesota Power a division of ALLETE, Inc.	11/09	Minnesota Power	Docket No. E-015/GR- 09-1151	Return on Equity

SPONSOR	DATE	CASE/APPLICANT	DOCKET No.	SUBJECT
CenterPoint Energy Resources Corp. d/b/a CenterPoint Energy Minnesota Gas	11/08	CenterPoint Energy Minnesota Gas	Docket No. G-008/GR-08-1075	Return on Equity
Otter Tail Power Corporation	10/07	Otter Tail Power Company	Docket No. E-017/GR-07-1178	Return on Equity
Xcel Energy, Inc.	11/05	NSP-Minnesota	Docket No. E-002/GR-05-1428	Return on Equity (electric)
Xcel Energy, Inc.	09/04	NSP Minnesota	Docket No. G-002/GR-04-1511	Cost of Capital (gas)
Mississippi Public Service Commission				
CenterPoint Energy Resources, Corp. d/b/a CenterPoint Energy Entex and CenterPoint Energy Mississippi Gas	07/09	CenterPoint Energy Mississippi Gas	Docket No. 09-UN-334	Return on Equity
Missouri Public Service Commission				
Union Electric Company d/b/a AmerenUE	09/10	Union Electric Company d/b/a AmerenUE	Case No. ER-2011-0028	Return on Equity (electric)
Union Electric Company d/b/a AmerenUE	06/10	Union Electric Company d/b/a AmerenUE	Case No. GR-2010-0363	Return on Equity (gas)
Nevada Public Utilities Commission				
Nevada Power Company	06/11	Nevada Power Company	Docket No. 11-06006	Return on Equity
New Hampshire Public Utilities Commission				
EnergyNorth Natural Gas d/b/a National Grid NH	02/10	EnergyNorth Natural Gas d/b/a National Grid NH	Docket No. DG 10-017	Return on Equity

SPONSOR	DATE	CASE/APPLICANT	DOCKET No.	SUBJECT
Unitil Energy Systems, Inc. ("Unitil"), EnergyNorth Natural Gas, Inc. d/b/a National Grid NH, Granite State Electric Company d/b/a National Grid, and Northern Utilities, Inc. – New Hampshire Division	08/08	Unitil Energy Systems, Inc. ("Unitil"), EnergyNorth Natural Gas, Inc. d/b/a National Grid NH, Granite State Electric Company d/b/a National Grid, and Northern Utilities, Inc. – New Hampshire Division	Docket No. DG 07-072	Carrying Charge Rate on Cash Working Capital
New Jersey Board of Public Utilities				
Pepco Holdings, Inc.	09/06	Atlantic City Electric Company	Docket No. EMO6090638	Divestiture and Valuation of Electric Generating Assets
Pepco Holdings, Inc.	12/05	Atlantic City Electric Company	Docket No. EM05121058	Market Value of Electric Generation Assets; Auction
Conectiv	06/03	Atlantic City Electric Company	Docket No. EO03020091	Market Value of Electric Generation Assets; Auction Process
New Mexico Public Regulation Commission				
Southwestern Public Service Company	02/11	Southwestern Public Service Company	Case No. 10-00395-UT	Return on Equity (electric)
Public Service Company of New Mexico	06/10	Public Service Company of New Mexico	Case No. 10-00086-UT	Return on Equity (electric)
Public Service Company of New Mexico	09/08	Public Service Company of New Mexico	Case No. 08-00273-UT	Return on Equity (electric)
Xcel Energy, Inc.	07/07	Southwestern Public Service Company	Case No. 07-00319-UT	Return on Equity (electric)
New York State Public Service Commission				
Orange and Rockland Utilities, Inc.	07/10	Orange and Rockland Utilities, Inc.	Case No. 10-E-0362	Return on Equity (electric)

SPONSOR	DATE	CASE/APPLICANT	DOCKET NO.	SUBJECT
Consolidated Edison Company of New York, Inc.	11/09	Consolidated Edison Company of New York, Inc.	Case No. 09-G-0795	Return on Equity (gas)
Consolidated Edison Company of New York, Inc.	11/09	Consolidated Edison Company of New York, Inc.	Case No. 09-S-0794	Return on Equity (steam)
Niagara Mohawk Power Corporation	07/01	Niagara Mohawk Power Corporation	Case No. 01-E-1046	Power Purchase and Sale Agreement; Standard Offer Service Agreement
North Dakota Public Service Commission				
Otter Tail Power Company	11/08	Otter Tail Power Company	Docket No. 08-862	Return on Equity (electric)
Oklahoma Corporation Commission				
CenterPoint Energy Resources Corp., D/B/A CenterPoint Energy Oklahoma Gas	03/09	CenterPoint Energy Oklahoma Gas	Docket No. PUD200900055	Return on Equity
Rhode Island Public Utilities Commission				
National Grid RI – Gas	08/08	National Grid RI – Gas	Docket No. 3943	Revenue Decoupling and Return on Equity
South Carolina Public Service Commission				
South Carolina Electric & Gas	03/10	South Carolina Electric & Gas	Docket No. 2009-489-E	Return on Equity
South Dakota Public Utilities Commission				
Otter Tail Power Company	08/10	Otter Tail Power Company	Docket No. EL10-011	Return on Equity (electric)
Northern States Power Company	06/09	South Dakota Division of Northern States Power	Docket No. EL09-009	Return on Equity (electric)
Otter Tail Power Company	10/08	Otter Tail Power Company	Docket No. EL08-030	Return on Equity (electric)

SPONSOR	DATE	CASE/APPLICANT	DOCKET No.	SUBJECT
Texas Public Utility Commission				
Oncor Electric Delivery Company, LLC	01/11	Oncor Electric Delivery Company, LLC	Docket No. 38929	Return on Equity
Texas-New Mexico Power Company	08/10	Texas-New Mexico Power Company	Docket No. 38480	Return on Equity (electric)
CenterPoint Energy Houston Electric LLC	07/10	CenterPoint Energy Houston Electric LLC	Docket No. 38339	Return on Equity
Xcel Energy, Inc.	05/10	Southwestern Public Service Company	Docket No. 38147	Return on Equity (electric)
Texas-New Mexico Power Company	08/08	Texas-New Mexico Power Company	Docket No. 36025	Return on Equity (electric)
Xcel Energy, Inc.	05/06	Southwestern Public Service Company	Docket No. 32766	Return on Equity (electric)
Texas Railroad Commission				
Centerpoint Energy Resources Corp. D/B/A Centerpoint Energy Entex and Centerpoint Energy Texas Gas	12/10	Centerpoint Energy Resources Corp. D/B/A Centerpoint Energy Entex and Centerpoint Energy Texas Gas	GUD 10038	Return on Equity
Atmos Pipeline - Texas	09/10	Atmos Pipeline - Texas	GUD 10000	Return on Equity
CenterPoint Energy Resources Corp. D/B/A CenterPoint Energy Entex and CenterPoint Energy Texas Gas	07/09	CenterPoint Energy Resources Corp. D/B/A CenterPoint Energy Entex and CenterPoint Energy Texas Gas	GUD 9902	Return on Equity
CenterPoint Energy Resources Corp. D/B/A CenterPoint Energy Texas Gas	03/08	CenterPoint Energy Resources Corp. D/B/A CenterPoint Energy Texas Gas	GUD 9791	Return on Equity
Utah Public Service Commission				

SPONSOR	DATE	CASE/APPLICANT	DOCKET No.	SUBJECT
Questar Gas Company	12/07	Questar Gas Company	Docket No. 07-057-13	Return on Equity
Vermont Public Service Board				
Central Vermont Public Service Corporation	12/10	Central Vermont Public Service Corporation	Docket No. 7627	Return on Equity (electric)
Green Mountain Power	04/06	Green Mountain Power	Docket Nos. 7175 and 7176	Return on Equity (electric)
Vermont Gas Systems, Inc.	12/05	Vermont Gas Systems	Docket Nos. 7109 and 7160	Return on Equity (gas)
Virginia State Corporation Commission				
Columbia Gas Of Virginia, Inc.	06/06	Columbia Gas Of Virginia, Inc.	Case No. PUE-2005-00098	Merger Synergies
Dominion Resources	10/01	Virginia Electric and Power Company	Case No. PUE000584	Corporate Structure and Electric Generation Strategy

HEVERT APPENDIX B

Flotation Cost Adjustment

Q. WHAT ARE FLOTATION COSTS?

A. Flotation costs are the costs incurred with the sale of new issues of common stock. Such costs typically include out-of-pocket expenditures for preparation, filing, legal, underwriting, and other costs associated with the issuance of equity securities.

Q. WHY IS IT IMPORTANT TO RECOGNIZE FLOTATION COSTS IN THE ALLOWED ROE?

A. In order to attract and retain new investors, a regulated utility must have the opportunity to earn an ROE that is both competitive and compensatory. To the extent that a company is denied the opportunity to recover prudently incurred flotation costs, actual returns will fall short of expected (or required) returns, thereby diminishing the company's ability to attract adequate capital on reasonable terms.

Q. ARE FLOTATION COSTS LIMITED TO EQUITY ISSUANCES PLANNED FOR THE TEST YEAR?

A. No. Flotation costs are not expenses that flow through the income statement. Rather, these costs are deducted from the permanent capital of the issuer and are thus reflected in the balance sheet. Recovery of investments is not limited to the year in which the

1 investment is made, and therefore no such temporal
2 limitation ought to be applied to the recovery of
3 flotation costs. Common equity has an indefinite life,
4 and due to the indeterminate life of an equity issuance,
5 flotation costs should be recovered through the ROE,
6 regardless of whether an issuance occurs during, or is
7 planned for, the test year.

8 **Q. ARE FLOTATION COSTS PART OF THE UTILITY'S INVESTED COSTS**
9 **OR PART OF THE UTILITY'S EXPENSES?**

10 A. Flotation costs are part of the invested costs of
11 the utility, which are properly reflected on the balance
12 sheet of the utility under "paid in capital." They are
13 not current expenses, and therefore are not reflected on
14 the income statement. Rather, like investments in rate
15 base or the issuance costs of long-term debt, flotation
16 costs are incurred over time. As a result, the great
17 majority of a utility's flotation cost is incurred prior
18 to the test year, but remains part of the cost structure
19 that exists during the test year and beyond, and as such,
20 should be recognized for ratemaking purposes. Therefore,
21 this adjustment is appropriate even if no new issuances
22 are planned in the near future because failure to allow
23 such an adjustment may deny the Company the necessary

1 opportunity to earn its required rate of return in the
2 future.

3 **Q. IS THE NEED TO CONSIDER FLOTATION COSTS ELIMINATED**
4 **BECAUSE PEPSCO IS A WHOLLY-OWNED SUBSIDIARY OF PHI?**

5 A. No, it is not. Although the Company is a
6 wholly-owned subsidiary of PHI, wholly-owned subsidiaries
7 receive equity capital from their parents and provide
8 returns on the capital that roll up to the parent, which
9 is designated to attract and raise capital based on the
10 returns of those subsidiaries. To deny recovery of
11 issuance costs associated with the capital that is
12 invested in the subsidiaries ultimately will penalize the
13 investors that fund the utility operations and will
14 inhibit the utility's ability to obtain new equity
15 capital at a reasonable cost.

16 **Q. WHY SHOULD THE COMPANY BE ALLOWED TO RECOVER THE**
17 **FLOTATION COSTS THAT WERE INCURRED FOR PRIOR EQUITY**
18 **ISSUANCES?**

19 A. While the majority of a utility's common stock
20 issuance costs are incurred prior to the test year, they
21 remain part of the cost structure that exists during the
22 test year and beyond. Therefore, even if no new
23 issuances are planned in the near future, this adjustment
24 is appropriate because failure to allow such an

1 adjustment may deny the Company the opportunity to
2 recover necessary and prudent costs incurred in acquiring
3 the funds needed to finance utility property, plant and
4 equipment.

5 **Q. IS THE NEED TO CONSIDER FLOTATION COSTS RECOGNIZED BY THE**
6 **ACADEMIC AND FINANCIAL COMMUNITIES?**

7 A. Yes, it is. The need to recover equity issuance
8 costs is recognized by the academic and financial
9 communities for the same fundamental reason that
10 companies reasonably expect to recover the costs of debt
11 issuances. As noted by Dr. Shannon Pratt:

12 Flotation costs occur when new issues of
13 stock or debt are sold to the public. The
14 firm usually incurs several kinds of
15 flotation or transaction costs, which reduce
16 the actual proceeds received by the firm.
17 Some of these are direct out-of-pocket
18 outlays, such as fees paid to underwriters,
19 legal expenses, and prospectus preparation
20 costs. Because of this reduction in
21 proceeds, the firm's required returns on
22 these proceeds equate to a higher return to
23 compensate for the additional costs.
24 Flotation costs can be accounted for either
25 by amortizing the cost, thus reducing the
26 cash flow to discount, or by incorporating
27 the cost into the cost of capital. Because
28 flotation costs are not typically applied to
29 operating cash flow, one must incorporate
30 them into the cost of capital.¹

A-1 Shannon P. Pratt, Cost of Capital Estimation and Applications,
Second Edition, at 220-221.

1 **Q. DO THE DCF AND CAPM MODELS ALREADY INCORPORATE INVESTOR**
2 **EXPECTATIONS OF A RETURN IN ORDER TO COMPENSATE FOR**
3 **FLOTATION COSTS?**

4 A. No, they do not. All the models used to estimate
5 the appropriate return on equity assume no "friction" or
6 transaction costs because these costs are not reflected
7 in the market price (in the case of the DCF model) or
8 risk premium (in the case of the CAPM). Therefore, it is
9 appropriate to consider flotation costs when determining
10 where within the range of reasonable returns Pepco's
11 authorized return should fall.

12 **Q. HAVE YOU CALCULATED THE EFFECT OF FLOTATION COSTS ON THE**
13 **RETURN ON EQUITY?**

14 A. Yes, I have. I modified the DCF calculation to
15 derive the dividend yield that would reimburse investors
16 for direct issuance costs. As shown in Exhibit (D)-7, I
17 included the actual flotation costs incurred by PHI at
18 the time of issuance, as well as recent issuances by
19 proxy group companies. Based on the weighted average
20 issuance costs² shown in Exhibit (D)-7, I believe that a
21 reasonable estimate of flotation costs is approximately
22 3.35 percent (i.e., 335 basis points).

A-2 The analysis of flotation costs excludes PHI's 2007 issuance of common stock due to unusual circumstances and terms that are not likely to be repeated.

1 **Q. HAVE YOU INCORPORATED A FLOTATION COST ADJUSTMENT INTO**
2 **YOUR ROE RECOMMENDATION?**

3 A. No, I have not. While it is my opinion that the
4 appropriate manner in which to reflect flotation costs is
5 through an adjustment to the allowed ROE, I understand
6 that it is the Commission's traditional practice to treat
7 flotation costs as an expense item in utilities' cost of
8 service.³ In recognition of this fact, Company Witness
9 Hook has included flotation costs in Exhibit PEPCO (F)-1.
10 However, if the Commission rejects flotation costs as an
11 expense item of cost of service, I believe it is
12 appropriate to include a 16 basis point (i.e., 0.16
13 percent) adjustment to the authorized ROE.

A-3 See, Formal Case No. 1076, *In the Matter of the Application of the Potomac Electric Power Company for Authority to Increase Existing Retail Rates and Charges for Electric Distribution Service*, Order No. 15710, March 2, 2010, at 25.

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Direct Exhibit
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Introduced as:
PEPCO _____ (D) -1

30 DAY CONSTANT GROWTH DCF

		[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]
Company		Annualized Dividend	Stock Price	Dividend Yield	Expected Dividend Yield	Zacks EPS Growth	Value Line EPS Growth	First Call	Average Growth Rate	Low DCF ROE	Mean DCF ROE	High DCF ROE
American Electric Power	AEP	\$1.84	\$37.12	4.96%	5.05%	4.00%	3.50%	3.71%	3.74%	8.54%	8.79%	9.06%
Cleco Corp.	CNL	\$1.12	\$34.84	3.21%	3.31%	7.00%	8.00%	3.00%	6.00%	6.26%	9.31%	11.34%
Empire District Electric	EDE	\$1.28	\$22.12	5.79%	5.97%	NA	7.00%	6.00%	6.50%	11.96%	12.47%	12.99%
Great Plains Energy Inc.	GXP	\$0.83	\$20.64	4.02%	4.17%	9.00%	6.00%	7.50%	7.50%	10.14%	11.67%	13.20%
Hawaiian Electric	HE	\$1.24	\$25.33	4.90%	5.12%	8.90%	11.00%	7.90%	9.27%	12.99%	14.39%	16.17%
IDACORP, Inc.	IDA	\$1.20	\$39.01	3.08%	3.14%	4.70%	4.00%	4.67%	4.46%	7.14%	7.60%	7.85%
Pinnacle West Capital	PNW	\$2.10	\$44.24	4.75%	4.89%	5.00%	6.00%	6.98%	5.99%	9.87%	10.88%	11.89%
Portland General	POR	\$1.06	\$25.10	4.22%	4.34%	5.00%	7.50%	4.38%	5.63%	8.70%	9.97%	11.88%
Southern Co.	SO	\$1.89	\$39.57	4.78%	4.91%	5.00%	6.00%	5.51%	5.50%	9.90%	10.41%	10.92%
Westar Energy	WR	\$1.28	\$27.08	4.73%	4.89%	5.50%	8.50%	6.28%	6.76%	10.36%	11.65%	13.43%
PROXY GROUP MEAN				4.44%	4.58%	6.01%	6.75%	5.59%	6.13%	9.58%	10.71%	11.87%

Notes

[1] Source: Bloomberg

[2] Source: Bloomberg. Based on indicated number of days historical average

[3] Equals Col. [1]/Col. [2]

[4] Equals Col. [3] x (1+(0.5 x Col. [8]))

[5] Source: Zacks

[6] Source: Value Line

[7] Source: First Call

[8] Equals Avg (Col. [5], [6], [7])

[9] Equals (Col. [3] x (1 + (0.5 x Minimum (Col. [5], [6], [7])))) + Minimum (Col. [5], [6], [7])

[10] Equals Col. [4] + Col. [8]

[11] Equals (Col. [3] x (1 + (0.5 x Maximum (Col. [5], [6], [7])))) + Maximum (Col. [5], [6], [7])

90 DAY CONSTANT GROWTH DCF

		[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]
Company		Annualized Dividend	Stock Price	Dividend Yield	Expected Dividend Yield	Zacks EPS Growth	Value Line EPS Growth	First Call	Average Growth Rate	Low DCF ROE	Mean DCF ROE	High DCF ROE
American Electric Power	AEP	\$1.84	\$36.00	5.11%	5.21%	4.00%	3.50%	3.71%	3.74%	8.70%	8.94%	9.21%
Cleco Corp.	CNL	\$1.12	\$33.45	3.35%	3.45%	7.00%	8.00%	3.00%	6.00%	6.40%	9.45%	11.48%
Empire District Electric	EDE	\$1.28	\$21.73	5.89%	6.08%	NA	7.00%	6.00%	6.50%	12.07%	12.58%	13.10%
Great Plains Energy Inc.	GXP	\$0.83	\$20.03	4.14%	4.30%	9.00%	6.00%	7.50%	7.50%	10.27%	11.80%	13.33%
Hawaiian Electric	HE	\$1.24	\$24.86	4.99%	5.22%	8.90%	11.00%	7.90%	9.27%	13.09%	14.49%	16.26%
IDACORP, Inc.	IDA	\$1.20	\$38.23	3.14%	3.21%	4.70%	4.00%	4.67%	4.46%	7.20%	7.67%	7.91%
Pinnacle West Capital	PNW	\$2.10	\$42.88	4.90%	5.04%	5.00%	6.00%	6.98%	5.99%	10.02%	11.04%	12.05%
Portland General	POR	\$1.06	\$23.85	4.44%	4.57%	5.00%	7.50%	4.38%	5.63%	8.92%	10.20%	12.11%
Southern Co.	SO	\$1.89	\$38.43	4.92%	5.05%	5.00%	6.00%	5.51%	5.50%	10.04%	10.56%	11.07%
Westar Energy	WR	\$1.28	\$26.36	4.86%	5.02%	5.50%	8.50%	6.28%	6.76%	10.49%	11.78%	13.56%
PROXY GROUP MEAN				4.57%	4.72%	6.01%	6.75%	5.59%	6.13%	9.72%	10.85%	12.01%

Notes

- [1] Source: Bloomberg
[2] Source: Bloomberg. Based on indicated number of days historical average
[3] Equals Col. [1]/Col. [2]
[4] Equals Col. [3] x (1+(0.5 x Col. [8]))
[5] Source: Zacks
[6] Source: Value Line
[7] Source: First Call
[8] Equals Avg (Col. [5], [6], [7])
[9] Equals (Col. [3] x (1 + (0.5 x Minimum (Col. [5], [6], [7])))) + Minimum (Col. [5], [6], [7])
[10] Equals Col. [4] + Col. [8]
[11] Equals (Col. [3] x (1 + (0.5 x Maximum (Col. [5], [6], [7])))) + Maximum (Col. [5], [6], [7])

180 DAY CONSTANT GROWTH DCF

		[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]
Company		Annualized Dividend	Stock Price	Dividend Yield	Expected Dividend Yield	Zacks EPS Growth	Value Line EPS Growth	First Call	Average Growth Rate	Low DCF ROE	Mean DCF ROE	High DCF ROE
American Electric Power	AEP	\$1.84	\$36.11	5.10%	5.19%	4.00%	3.50%	3.71%	3.74%	8.68%	8.93%	9.20%
Cleco Corp.	CNL	\$1.12	\$32.04	3.50%	3.60%	7.00%	8.00%	3.00%	6.00%	6.55%	9.60%	11.64%
Empire District Electric	EDE	\$1.28	\$21.51	5.95%	6.14%	NA	7.00%	6.00%	6.50%	12.13%	12.64%	13.16%
Great Plains Energy Inc.	GXP	\$0.83	\$19.59	4.24%	4.40%	9.00%	6.00%	7.50%	7.50%	10.36%	11.90%	13.43%
Hawaiian Electric	HE	\$1.24	\$23.82	5.21%	5.45%	8.90%	11.00%	7.90%	9.27%	13.31%	14.71%	16.49%
IDACORP, Inc.	IDA	\$1.20	\$37.44	3.21%	3.28%	4.70%	4.00%	4.67%	4.46%	7.27%	7.73%	7.98%
Pinnacle West Capital	PNW	\$2.10	\$42.09	4.99%	5.14%	5.00%	6.00%	6.98%	5.99%	10.11%	11.13%	12.14%
Portland General	POR	\$1.06	\$22.54	4.70%	4.84%	5.00%	7.50%	4.38%	5.63%	9.19%	10.46%	12.38%
Southern Co.	SO	\$1.89	\$38.17	4.95%	5.09%	5.00%	6.00%	5.51%	5.50%	10.07%	10.59%	11.10%
Westar Energy	WR	\$1.28	\$25.67	4.99%	5.16%	5.50%	8.50%	6.28%	6.76%	10.62%	11.92%	13.70%
PROXY GROUP MEAN				4.68%	4.83%	6.01%	6.75%	5.59%	6.13%	9.83%	10.96%	12.12%

Notes

[1] Source: Bloomberg

[2] Source: Bloomberg. Based on indicated number of days historical average

[3] Equals Col. [1]/Col. [2]

[4] Equals Col. [3] x (1+(0.5 x Col. [8]))

[5] Source: Zacks

[6] Source: Value Line

[7] Source: First Call

[8] Equals Avg (Col. [5], [6], [7])

[9] Equals (Col. [3] x (1 + (0.5 x Minimum (Col. [5], [6], [7])))) + Minimum (Col. [5], [6], [7])

[10] Equals Col. [4] + Col. [8]

[11] Equals (Col. [3] x (1 + (0.5 x Maximum (Col. [5], [6], [7])))) + Maximum (Col. [5], [6], [7])

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Introduced as:
PEPCO _____ (D)-2

AVERAGE HISTORICAL BETAS
VALUE LINE AND BLOOMBERG

		Value Line	Bloomberg	Average
American Electric Power	AEP	0.70	0.79	0.75
Cleco Corp.	CNL	0.65	0.79	0.72
Empire District Electric	EDE	0.70	0.68	0.69
Great Plains Energy Inc.	GXP	0.75	0.85	0.80
Hawaiian Electric	HE	0.70	0.78	0.74
IDACORP, Inc.	IDA	0.70	0.86	0.78
Pinnacle West Capital	PNW	0.70	0.85	0.78
Portland General	POR	0.75	0.76	0.76
Southern Co.	SO	0.55	0.62	0.59
Westar Energy	WR	0.75	0.84	0.80
Average Beta		0.695	0.783	0.739

Sources: Value Line and Bloomberg.

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Introduced as:
PEPCO _____ (D)-3

CAPM USING ALTERNATIVE MARKET RISK PREMIUM CALCULATIONS

	[3]	[4]	[5]	[6]	[7]	[8]
	Risk Free Rate	Average Beta	Market Risk Premium		Return on Equity	
			Sharpe Ratio Derived	Market DCF Derived	Sharpe Ratio Derived	Market DCF Derived
PROXY GROUP CURRENT BETA						
[1] Current 30-Year Treasury (30-day average)	4.34%	0.732	7.22%	8.34%	9.62%	10.44%
[2] Near-Term Projected 30-Year Treasury	4.88%	0.732	7.22%	8.34%	10.17%	10.99%
PROXY GROUP HISTORICAL BETA						
[1] Current 30-Year Treasury (30-day average)	4.34%	0.739	7.22%	8.34%	9.68%	10.50%
[2] Near-Term Projected 30-Year Treasury	4.88%	0.739	7.22%	8.34%	10.22%	11.05%

Notes:

[1] Source: Bloomberg

[2] Source: Blue Chip Financial Forecasts, Vol. 30, No. 5, May 1, 2011, at 2

[3] see Notes [1] and [2]

[4] Source: Current = PEPCO_(D)-4, Historical = PEPCO_(D)-2

[5] Equals Col. [13]

[6] Source: PEPCO_(D)-3, page 3

[7] Equals (Col. [4] x Col. [5]) + Col. [3]

[8] Equals (Col. [4] x Col. [6]) + Col. [3]

MARKET RISK PREMIUM USING EXPECTED MARKET SHARPE RATIO

[9]	[10]	[11]	[12]	[13]
RP_h	Vol_h	VOL_e	Historical Market Sharpe Ratio	RP_e
6.70%	20.28%	21.87%	33.04%	7.22%

	[14]	[15]	[16]	[17]
		Sep11 VIX	Oct11 VIX	Nov11 VIX
Date	VXV	Futures	Futures	Futures
5/31/2011	17.56	20.75	21.90	22.30
5/27/2011	18.13	21.20	22.30	22.70
5/26/2011	18.19	21.65	22.75	23.05
5/25/2011	18.87	22.15	23.20	23.50
5/24/2011	19.17	22.40	23.45	23.65
5/23/2011	19.79	22.60	23.55	23.75
5/20/2011	19.05	22.45	23.30	23.50
5/19/2011	18.17	21.85	22.65	22.85
5/18/2011	18.53	21.85	22.55	22.75
5/17/2011	19.45	22.10	22.80	23.05
5/16/2011	19.87	22.30	22.90	23.10
5/13/2011	19.07	22.15	22.80	22.95
5/12/2011	18.44	21.90	22.55	22.75
5/11/2011	19.05	22.05	22.70	22.90
5/10/2011	18.37	21.75	22.45	22.60
5/9/2011	19.20	22.15	22.85	23.10
5/6/2011	19.91	22.55	23.30	23.55
5/5/2011	19.84	22.70	23.50	23.65
5/4/2011	19.44	22.55	23.30	23.55
5/3/2011	19.11	22.45	23.20	23.45
5/2/2011	18.39	22.15	23.05	23.25
4/29/2011	17.50	21.65	22.55	22.90
4/28/2011	17.52	22.00	22.75	23.05
4/27/2011	17.90	22.30	23.00	23.20
4/26/2011	18.27	22.50	23.25	23.50
4/25/2011	18.55	22.65	23.50	24.05
4/21/2011	18.35	22.90	23.65	24.15
4/20/2011	18.48	23.05	23.80	24.30
4/19/2011	19.18	23.50	24.20	24.50
4/18/2011	19.92	23.80	24.50	24.75
Average	21.87			

Notes:

[9] Source: Morningstar, Inc.

RP_h = historical arithmetic average Risk Premium

[10] Source: Morningstar, Inc.

Vol_h = historical market volatility

[11] Vol_e = expected market volatility (average of Cols. [14]-[17])

[12] Equals Col. [9] / Col. [10]

[13] Equals Col. [11] x Col. [12]

[14] Source: Bloomberg

[15] Source: Bloomberg

[16] Source: Bloomberg

[17] Source: Bloomberg

$$\frac{RP_h}{Vol_h} \times Vol_e = RP_e$$

ESTIMATED MARKET RISK PREMIUM DERIVED FROM ANALYSTS LONG-TERM GROWTH ESTIMATES

[1] Estimated Weighted Index Dividend Yield	[2] Weighted Index Long-Term Growth Rate	[3] S&P 500 Est. Required Market Return
1.84%	10.73%	12.68%
[4] Current 30-Year Treasury (30-day average)		4.34%
[5] Implied Market Risk Premium:		8.34%
[6] Percent of Index Capitalization Represented by Estimate:		97.31%

STANDARD AND POOR'S 500 INDEX

Name	Ticker	[7] Weight in Index	[8] Long-Term Growth Est.	[9] Cap-Weighted Long-Term Growth Est.	[10] Estimated Dividend Yield	[11] Cap-Weighted Dividend Yield
AGILENT TECHNOLOGIES INC	A	0.14%	15.00%	0.02%	0.00%	0.00%
ALCOA INC	AA	0.14%	3.00%	0.00%	0.71%	0.00%
APPLE INC	AAPL	2.55%	21.16%	0.54%	0.00%	0.00%
AMERISOURCEBERGEN CORP	ABC	0.09%	11.60%	0.01%	0.81%	0.00%
ABBOTT LABORATORIES	ABT	0.65%	9.68%	0.06%	3.62%	0.02%
ACE LTD	ACE	0.19%	11.40%	0.02%	1.95%	0.00%
ADOBE SYSTEMS INC	ADBE	0.14%	10.78%	0.02%	0.00%	0.00%
ANALOG DEVICES INC	ADI	0.10%	11.75%	0.01%	2.23%	0.00%
ARCHER-DANIELS-MIDLAND CO	ADM	0.16%	10.00%	0.02%	1.88%	0.00%
AUTOMATIC DATA PROCESSING	ADP	0.22%	10.71%	0.02%	2.58%	0.01%
AUTODESK INC	ADSK	0.08%	13.40%	0.01%	0.00%	0.00%
AMEREN CORPORATION	AEE	0.06%	na	na	5.19%	na
AMERICAN ELECTRIC POWER	AEP	0.15%	4.50%	0.01%	4.81%	0.01%
AES CORP	AES	0.08%	9.50%	0.01%	0.00%	0.00%
AETNA INC	AET	0.13%	11.17%	0.01%	1.11%	0.00%
AFLAC INC	AFL	0.18%	10.80%	0.02%	2.57%	0.00%
ALLERGAN INC	AGN	0.20%	13.91%	0.03%	0.21%	0.00%
AMERICAN INTERNATIONAL GROUP	AIG	0.43%	9.00%	0.04%	0.00%	0.00%
APARTMENT INVT & MGMT CO -A	AIV	0.03%	9.74%	0.00%	1.80%	0.00%
ASSURANT INC	AIZ	0.03%	10.00%	0.00%	1.85%	0.00%
AKAMAI TECHNOLOGIES INC	AKAM	0.05%	17.70%	0.01%	0.00%	0.00%
AK STEEL HOLDING CORP	AKS	0.01%	na	na	1.31%	na
ALLSTATE CORP	ALL	0.13%	9.00%	0.01%	2.66%	0.00%
ALTERA CORP	ALTR	0.12%	15.25%	0.02%	0.49%	0.00%
APPLIED MATERIALS INC	AMAT	0.14%	9.67%	0.01%	2.07%	0.00%
ADVANCED MICRO DEVICES	AMD	0.05%	12.77%	0.01%	0.00%	0.00%
AMGEN INC	AMGN	0.45%	7.92%	0.04%	0.74%	0.00%
AMERIPRISE FINANCIAL INC	AMP	0.12%	12.30%	0.01%	1.33%	0.00%
AMERICAN TOWER CORP-CL A	AMT	0.18%	18.36%	0.03%	0.00%	0.00%
AMAZON.COM INC	AMZN	0.71%	28.72%	0.20%	0.00%	0.00%
AUTONATION INC	AN	0.04%	19.87%	0.01%	0.00%	0.00%
ABERCROMBIE & FITCH CO-CL A	ANF	0.05%	27.25%	0.01%	0.93%	0.00%
AON CORP	AON	0.14%	8.33%	0.01%	1.29%	0.00%
APACHE CORP	APA	0.38%	8.89%	0.03%	0.52%	0.00%
ANADARKO PETROLEUM CORP	APC	0.32%	18.22%	0.06%	0.46%	0.00%
AIR PRODUCTS & CHEMICALS INC	APD	0.16%	10.29%	0.02%	2.25%	0.00%
AMPHENOL CORP-CL A	APH	0.08%	10.95%	0.01%	0.11%	0.00%
APOLLO GROUP INC-CL A	APOL	0.05%	2.51%	0.00%	0.00%	0.00%
AIRGAS INC	ARG	0.04%	13.23%	0.01%	1.69%	0.00%
ALLEGHENY TECHNOLOGIES INC	ATI	0.06%	na	na	1.07%	na
AVALONBAY COMMUNITIES INC	AVB	0.09%	11.49%	0.01%	2.69%	0.00%
AVON PRODUCTS INC	AVP	0.10%	10.50%	0.01%	3.19%	0.00%
AVERY DENNISON CORP	AVY	0.04%	7.00%	0.00%	2.27%	0.00%
AMERICAN EXPRESS CO	AXP	0.49%	10.83%	0.05%	1.45%	0.01%
AUTOZONE INC	AZO	0.10%	12.98%	0.01%	0.00%	0.00%
BOEING CO/THE	BA	0.46%	12.25%	0.06%	2.20%	0.01%
BANK OF AMERICA CORP	BAC	0.95%	8.58%	0.08%	0.47%	0.00%
BAXTER INTERNATIONAL INC	BAX	0.27%	10.50%	0.03%	2.12%	0.01%
BED BATH & BEYOND INC	BBBY	0.11%	13.46%	0.01%	0.00%	0.00%
BB&T CORP	BBT	0.15%	7.00%	0.01%	2.35%	0.00%
BEST BUY CO INC	BBY	0.10%	11.23%	0.01%	1.91%	0.00%
CR BARD INC	BCR	0.08%	11.33%	0.01%	0.69%	0.00%
BECTON DICKINSON AND CO	BDX	0.15%	9.84%	0.02%	1.89%	0.00%
FRANKLIN RESOURCES INC	BEN	0.23%	9.33%	0.02%	0.77%	0.00%
BROWN-FORMAN CORP-CLASS B	BF/B	0.05%	na	na	1.82%	na
BAKER HUGHES INC	BHI	0.26%	19.18%	0.05%	0.79%	0.00%
BIG LOTS INC	BIG	0.02%	12.50%	0.00%	na	na

		[7]	[8]	[9]	[10]	[11]
Name	Ticker	Weight in Index	Long-Term Growth Est.	Cap-Weighted Long-Term Growth Est.	Estimated Dividend Yield	Cap-Weighted Dividend Yield
BIOGEN IDEC INC	BIIB	0.18%	9.74%	0.02%	0.00%	0.00%
BANK OF NEW YORK MELLON CORP	BK	0.28%	7.37%	0.02%	1.74%	0.00%
BLACKROCK INC	BLK	0.22%	16.33%	0.04%	2.65%	0.01%
BALL CORP	BLL	0.05%	5.00%	0.00%	0.70%	0.00%
BMC SOFTWARE INC	BMC	0.08%	15.50%	0.01%	0.00%	0.00%
BEMIS COMPANY	BMS	0.03%	8.30%	0.00%	2.98%	0.00%
BRISTOL-MYERS SQUIBB CO	BMJ	0.39%	1.72%	0.01%	4.49%	0.02%
BROADCOM CORP-CL A	BRCM	0.14%	16.06%	0.02%	0.99%	0.00%
BERKSHIRE HATHAWAY INC-CL B	BRK/B	0.67%	na	na	na	na
BOSTON SCIENTIFIC CORP	BSX	0.09%	6.17%	0.01%	0.00%	0.00%
PEABODY ENERGY CORP	BTU	0.13%	40.00%	0.05%	0.57%	0.00%
BOSTON PROPERTIES INC	BXP	0.13%	7.22%	0.01%	1.87%	0.00%
CITIGROUP INC	C	0.96%	5.33%	0.05%	0.15%	0.00%
CA INC	CA	0.09%	11.33%	0.01%	0.82%	0.00%
CONAGRA FOODS INC	CAG	0.08%	7.73%	0.01%	3.47%	0.00%
CARDINAL HEALTH INC	CAH	0.13%	11.88%	0.02%	1.54%	0.00%
CAMERON INTERNATIONAL CORP	CAM	0.09%	13.38%	0.01%	0.00%	0.00%
CATERPILLAR INC	CAT	0.54%	8.35%	0.05%	1.68%	0.01%
CHUBB CORP	CB	0.15%	9.20%	0.01%	2.44%	0.00%
CB RICHARD ELLIS GROUP INC-A	CBG	0.07%	11.50%	0.01%	0.00%	0.00%
CBS CORP-CLASS B NON VOTING	CBS	0.14%	15.90%	0.02%	1.07%	0.00%
COCA-COLA ENTERPRISES	CCE	0.08%	9.00%	0.01%	1.81%	0.00%
CARNIVAL CORP	CCL	0.19%	10.58%	0.02%	2.36%	0.00%
CONSTELLATION ENERGY GROUP	CEG	0.06%	6.00%	0.00%	2.58%	0.00%
CELGENE CORP	CELG	0.22%	24.76%	0.06%	0.00%	0.00%
CEPHALON INC	CEPH	0.05%	9.00%	0.00%	na	na
CERNER CORP	CERN	0.08%	19.18%	0.02%	0.00%	0.00%
CF INDUSTRIES HOLDINGS INC	CF	0.09%	12.00%	0.01%	0.26%	0.00%
CAREFUSION CORP	CFN	0.05%	16.91%	0.01%	0.00%	0.00%
CHESAPEAKE ENERGY CORP	CHK	0.16%	5.50%	0.01%	1.00%	0.00%
C.H. ROBINSON WORLDWIDE INC	CHRW	0.11%	15.37%	0.02%	1.46%	0.00%
CIGNA CORP	CI	0.11%	10.10%	0.01%	0.11%	0.00%
CINCINNATI FINANCIAL CORP	CINF	0.04%	na	na	5.29%	na
COLGATE-PALMOLIVE CO	CL	0.34%	9.50%	0.03%	2.53%	0.01%
CLIFFS NATURAL RESOURCES INC	CLF	0.10%	na	na	0.62%	na
CLOXOX COMPANY	CLX	0.07%	9.00%	0.01%	3.13%	0.00%
COMERICA INC	CMA	0.05%	5.80%	0.00%	1.12%	0.00%
COMCAST CORP-CLASS A	CMCSA	0.42%	14.63%	0.06%	1.78%	0.01%
CME GROUP INC	CME	0.15%	13.75%	0.02%	1.90%	0.00%
CHIPOTLE MEXICAN GRILL INC	CMG	0.07%	21.56%	0.02%	0.00%	0.00%
CUMMINS INC	CMI	0.16%	11.67%	0.02%	1.01%	0.00%
CMS ENERGY CORP	CMS	0.04%	5.78%	0.00%	4.25%	0.00%
CENTERPOINT ENERGY INC	CNP	0.07%	5.70%	0.00%	4.09%	0.00%
CONSOL ENERGY INC	CNX	0.09%	47.00%	0.04%	0.78%	0.00%
CAPITAL ONE FINANCIAL CORP	COF	0.20%	9.92%	0.02%	0.52%	0.00%
CABOT OIL & GAS CORP	COG	0.05%	20.00%	0.01%	0.20%	0.00%
COACH INC	COH	0.15%	15.71%	0.02%	1.03%	0.00%
ROCKWELL COLLINS INC	COL	0.08%	8.78%	0.01%	1.66%	0.00%
CONOCOPHILLIPS	COP	0.82%	2.82%	0.02%	3.53%	0.03%
COSTCO WHOLESALE CORP	COST	0.29%	13.21%	0.04%	1.02%	0.00%
COVIDIEN PLC	COV	0.22%	12.17%	0.03%	1.42%	0.00%
CAMPBELL SOUP CO	CPB	0.09%	6.62%	0.01%	3.26%	0.00%
COMPUWARE CORP	CPWR	0.02%	5.00%	0.00%	na	na
SALESFORCE.COM INC	CRM	0.16%	26.75%	0.04%	0.00%	0.00%
COMPUTER SCIENCES CORP	CSC	0.05%	9.00%	0.00%	0.80%	0.00%
CISCO SYSTEMS INC	CSCO	0.74%	10.18%	0.08%	0.71%	0.01%
CSX CORP	CSX	0.23%	14.99%	0.03%	1.49%	0.00%
CINTAS CORP	CTAS	0.04%	10.67%	0.00%	1.50%	0.00%
CENTURYLINK INC	CTL	0.21%	na	na	6.72%	na
COGNIZANT TECH SOLUTIONS-A	CTSH	0.18%	18.96%	0.03%	0.00%	0.00%
CITRIX SYSTEMS INC	CTXS	0.13%	14.19%	0.02%	0.00%	0.00%
CABLEVISION SYSTEMS-NY GRP-A	CVC	0.07%	12.00%	0.01%	1.52%	0.00%
COVENTRY HEALTH CARE INC	CVH	0.04%	8.88%	0.00%	0.00%	0.00%
CVS CAREMARK CORP	CVS	0.42%	11.00%	0.05%	1.24%	0.01%
CHEVRON CORP	CVX	1.68%	2.34%	0.04%	2.92%	0.05%
DOMINION RESOURCES INC/VA	D	0.22%	3.76%	0.01%	4.12%	0.01%
DU PONT (E.I.) DE NEMOURS	DD	0.39%	8.89%	0.04%	3.07%	0.01%
DEERE & CO	DE	0.29%	9.00%	0.03%	1.55%	0.00%
DELL INC	DELL	0.24%	8.00%	0.02%	0.00%	0.00%
DEAN FOODS CO	DF	0.02%	8.05%	0.00%	na	na
DISCOVER FINANCIAL SERVICES	DFS	0.10%	7.33%	0.01%	1.03%	0.00%

		[7]	[8]	[9]	[10]	[11]
		Cap-Weighted				
Name	Ticker	Weight in Index	Long-Term Growth Est.	Long-Term Growth Est.	Estimated Dividend Yield	Cap-Weighted Dividend Yield
QUEST DIAGNOSTICS INC	DGX	0.07%	11.55%	0.01%	0.71%	0.00%
DR HORTON INC	DHI	0.03%	7.67%	0.00%	1.23%	0.00%
DANAHER CORP	DHR	0.29%	15.70%	0.04%	0.17%	0.00%
WALT DISNEY CO/THE	DIS	0.63%	16.94%	0.11%	0.93%	0.01%
DISCOVERY COMMUNICATIONS-A	DISCA	0.05%	22.16%	0.01%	0.00%	0.00%
DUN & BRADSTREET CORP	DNB	0.03%	11.15%	0.00%	1.80%	0.00%
DENBURY RESOURCES INC	DNR	0.07%	18.98%	0.01%	0.00%	0.00%
DIAMOND OFFSHORE DRILLING	DO	0.08%	18.00%	0.01%	4.75%	0.00%
DOVER CORP	DOV	0.10%	14.50%	0.01%	1.68%	0.00%
DOW CHEMICAL CO/THE	DOW	0.34%	7.50%	0.03%	2.35%	0.01%
DR PEPPER SNAPPLE GROUP INC	DPS	0.07%	8.50%	0.01%	2.64%	0.00%
DARDEN RESTAURANTS INC	DRI	0.06%	12.54%	0.01%	2.53%	0.00%
DTE ENERGY COMPANY	DTE	0.07%	4.50%	0.00%	4.40%	0.00%
DIRECTV-CLASS A	DTV	0.31%	19.49%	0.06%	0.00%	0.00%
DUKE ENERGY CORP	DUK	0.20%	4.50%	0.01%	5.35%	0.01%
DEVRY INC	DV	0.03%	11.57%	0.00%	0.32%	0.00%
DAVITA INC	DVA	0.06%	12.39%	0.01%	0.00%	0.00%
DEVON ENERGY CORPORATION	DVN	0.29%	9.21%	0.03%	0.80%	0.00%
EBAY INC	EBAY	0.32%	11.78%	0.04%	0.00%	0.00%
ECOLAB INC	ECL	0.10%	13.50%	0.01%	1.28%	0.00%
CONSOLIDATED EDISON INC	ED	0.12%	3.49%	0.00%	4.53%	0.01%
EQUIFAX INC	EFX	0.04%	10.00%	0.00%	1.69%	0.00%
EDISON INTERNATIONAL	EIX	0.10%	4.25%	0.00%	3.29%	0.00%
ESTEE LAUDER COMPANIES-CL A	EL	0.10%	12.33%	0.01%	0.70%	0.00%
EMC CORP/MASS	EMC	0.47%	15.00%	0.07%	0.00%	0.00%
EASTMAN CHEMICAL CO	EMN	0.06%	10.00%	0.01%	1.77%	0.00%
EMERSON ELECTRIC CO	EMR	0.33%	14.50%	0.05%	2.58%	0.01%
EOG RESOURCES INC	EOG	0.23%	43.95%	0.10%	0.61%	0.00%
EL PASO CORP	EP	0.13%	1.20%	0.00%	0.19%	0.00%
EQUITY RESIDENTIAL	EQR	0.15%	7.63%	0.01%	2.51%	0.00%
EQT CORP	EQT	0.06%	18.47%	0.01%	1.62%	0.00%
ELECTRONIC ARTS INC	ERTS	0.06%	16.67%	0.01%	0.00%	0.00%
EXPRESS SCRIPTS INC	ESRX	0.25%	19.56%	0.05%	0.00%	0.00%
E*TRADE FINANCIAL CORP	ETFC	0.04%	51.00%	0.02%	0.00%	0.00%
EATON CORP	ETN	0.14%	10.25%	0.01%	2.94%	0.00%
ENTERGY CORP	ETR	0.10%	2.00%	0.00%	4.99%	0.00%
EDWARDS LIFESCIENCES CORP	EW	0.08%	21.38%	0.02%	0.00%	0.00%
EXELON CORP	EXC	0.22%	na	na	5.05%	na
EXPEDITORS INTL WASH INC	EXPD	0.09%	14.97%	0.01%	0.85%	0.00%
EXPEDIA INC	EXPE	0.06%	9.26%	0.01%	1.00%	0.00%
FORD MOTOR CO	F	0.44%	7.82%	0.03%	0.00%	0.00%
FASTENAL CO	FAST	0.08%	19.10%	0.01%	1.94%	0.00%
FREEMPORT-MCMORAN COPPER	FCX	0.39%	9.30%	0.04%	3.15%	0.01%
FAMILY DOLLAR STORES	FDO	0.05%	14.40%	0.01%	1.19%	0.00%
FEDEX CORP	FDX	0.24%	13.68%	0.03%	0.51%	0.00%
FIRSTENERGY CORP	FE	0.15%	3.20%	0.00%	4.93%	0.01%
F5 NETWORKS INC	FFIV	0.07%	23.40%	0.02%	0.00%	0.00%
FIRST HORIZON NATIONAL CORP	FHN	0.02%	7.50%	0.00%	0.44%	0.00%
FEDERATED INVESTORS INC-CL B	FII	0.02%	5.00%	0.00%	3.85%	0.00%
FIDELITY NATIONAL INFORMATIO	FIS	0.08%	13.50%	0.01%	0.52%	0.00%
FISERV INC	FISV	0.07%	11.90%	0.01%	0.00%	0.00%
FIFTH THIRD BANCORP	FITB	0.10%	5.00%	0.00%	1.71%	0.00%
FLIR SYSTEMS INC	FLIR	0.05%	14.24%	0.01%	0.66%	0.00%
FLUOR CORP	FLR	0.10%	17.50%	0.02%	0.62%	0.00%
FLOWSERVE CORP	FLS	0.05%	11.50%	0.01%	1.03%	0.00%
FMC CORP	FMC	0.05%	11.17%	0.01%	0.63%	0.00%
FORTUNE BRANDS INC	FO	0.08%	11.00%	0.01%	1.19%	0.00%
FOREST LABORATORIES INC	FRX	0.08%	1.19%	0.00%	0.00%	0.00%
FIRST SOLAR INC	FSLR	0.09%	17.71%	0.02%	0.00%	0.00%
FMC TECHNOLOGIES INC	FTI	0.09%	13.07%	0.01%	0.00%	0.00%
FRONTIER COMMUNICATIONS CORP	FTR	0.07%	na	na	8.48%	na
NICOR INC	GAS	0.02%	4.00%	0.00%	3.38%	0.00%
GANNETT CO	GCI	0.03%	5.50%	0.00%	1.12%	0.00%
GENERAL DYNAMICS CORP	GD	0.22%	9.71%	0.02%	2.39%	0.01%
GENERAL ELECTRIC CO	GE	1.66%	11.08%	0.18%	2.87%	0.05%
GILEAD SCIENCES INC	GILD	0.26%	15.89%	0.04%	0.00%	0.00%
GENERAL MILLS INC	GIS	0.20%	8.32%	0.02%	2.76%	0.01%
CORNING INC	GLW	0.25%	11.67%	0.03%	0.98%	0.00%
GAMESTOP CORP-CLASS A	GME	0.03%	11.75%	0.00%	0.00%	0.00%
GENWORTH FINANCIAL INC-CL A	GNW	0.04%	13.67%	0.01%	0.00%	0.00%
GOOGLE INC-CL A	GOOG	1.07%	16.60%	0.18%	0.00%	0.00%
GENUINE PARTS CO	GPC	0.07%	9.77%	0.01%	3.29%	0.00%
GAP INC/THE	GPS	0.09%	9.46%	0.01%	2.21%	0.00%
GOODRICH CORP	GR	0.09%	12.10%	0.01%	1.30%	0.00%
GOLDMAN SACHS GROUP INC	GS	0.58%	12.00%	0.07%	1.00%	0.01%

		[7]	[8]	[9]	[10]	[11]
Name	Ticker	Weight in Index	Long-Term Growth Est.	Cap-Weighted Long-Term Growth Est.	Estimated Dividend Yield	Cap-Weighted Dividend Yield
GOODYEAR TIRE & RUBBER CO	GT	0.03%	26.37%	0.01%	0.00%	0.00%
WW GRAINGER INC	GWV	0.08%	13.74%	0.01%	1.55%	0.00%
HALLIBURTON CO	HAL	0.37%	15.20%	0.06%	0.72%	0.00%
HARMAN INTERNATIONAL	HAR	0.03%	20.00%	0.01%	na	na
HASBRO INC	HAS	0.05%	10.00%	0.00%	2.62%	0.00%
HUNTINGTON BANCSHARES INC	HBAN	0.05%	5.50%	0.00%	1.10%	0.00%
HUDSON CITY BANCORP INC	HCBC	0.04%	4.50%	0.00%	4.07%	0.00%
HEALTH CARE REIT INC	HCN	0.07%	9.99%	0.01%	5.36%	0.00%
HCP INC	HCP	0.12%	7.51%	0.01%	5.05%	0.01%
HOME DEPOT INC	HD	0.47%	12.90%	0.06%	2.76%	0.01%
HESS CORP	HES	0.21%	8.96%	0.02%	0.51%	0.00%
HARTFORD FINANCIAL SVCS GRP	HIG	0.09%	8.20%	0.01%	1.22%	0.00%
HJ HEINZ CO	HNZ	0.14%	8.00%	0.01%	3.49%	0.00%
HARLEY-DAVIDSON INC	HOG	0.07%	10.50%	0.01%	1.14%	0.00%
HONEYWELL INTERNATIONAL INC	HON	0.37%	15.83%	0.06%	2.20%	0.01%
STARWOOD HOTELS & RESORTS	HOT	0.09%	19.48%	0.02%	0.56%	0.00%
HELMERICH & PAYNE	HP	0.05%	9.00%	0.00%	0.40%	0.00%
HEWLETT-PACKARD CO	HPQ	0.64%	10.00%	0.06%	0.95%	0.01%
H&R BLOCK INC	HRB	0.04%	10.00%	0.00%	3.46%	0.00%
HORMEL FOODS CORP	HRL	0.06%	11.00%	0.01%	1.74%	0.00%
HARRIS CORP	HRS	0.05%	9.00%	0.00%	2.08%	0.00%
HOSPIRA INC	HSP	0.07%	12.18%	0.01%	0.00%	0.00%
HOST HOTELS & RESORTS INC	HST	0.10%	11.38%	0.01%	0.74%	0.00%
HERSHEY CO/THE	HSY	0.07%	7.50%	0.01%	2.46%	0.00%
HUMANA INC	HUM	0.11%	9.28%	0.01%	0.44%	0.00%
INTL BUSINESS MACHINES CORP	IBM	1.63%	10.64%	0.17%	1.60%	0.03%
INTERCONTINENTALEXCHANGE INC	ICE	0.07%	16.50%	0.01%	0.00%	0.00%
INTL FLAVORS & FRAGRANCES	IFF	0.04%	9.33%	0.00%	1.78%	0.00%
INTL GAME TECHNOLOGY	IGT	0.04%	16.00%	0.01%	1.26%	0.00%
INTEL CORP	INTC	0.95%	11.27%	0.11%	3.35%	0.03%
INTUIT INC	INTU	0.13%	13.71%	0.02%	0.00%	0.00%
INTERNATIONAL PAPER CO	IP	0.11%	5.50%	0.01%	3.18%	0.00%
INTERPUBLIC GROUP OF COS INC	IPG	0.05%	11.67%	0.01%	1.95%	0.00%
INGERSOLL-RAND PLC	IR	0.13%	12.48%	0.02%	0.89%	0.00%
IRON MOUNTAIN INC	IRM	0.05%	15.67%	0.01%	3.22%	0.00%
INTUITIVE SURGICAL INC	ISRG	0.11%	21.00%	0.02%	na	na
ITT CORP	ITT	0.08%	9.50%	0.01%	1.94%	0.00%
ILLINOIS TOOL WORKS	ITW	0.23%	13.06%	0.03%	2.61%	0.01%
INVESCO LTD	IVZ	0.09%	12.75%	0.01%	1.95%	0.00%
JABIL CIRCUIT INC	JBL	0.04%	12.50%	0.00%	1.30%	0.00%
JOHNSON CONTROLS INC	JCI	0.21%	16.07%	0.03%	1.46%	0.00%
J.C. PENNEY CO INC	JCP	0.06%	10.10%	0.01%	2.35%	0.00%
JDS UNIPHASE CORP	JDSU	0.04%	6.00%	0.00%	0.00%	0.00%
JACOBS ENGINEERING GROUP INC	JEC	0.05%	14.00%	0.01%	0.00%	0.00%
JOHNSON & JOHNSON	JNJ	1.47%	7.00%	0.10%	3.36%	0.05%
JUNIPER NETWORKS INC	JNPR	0.16%	17.85%	0.03%	0.00%	0.00%
JANUS CAPITAL GROUP INC	JNS	0.02%	7.75%	0.00%	1.43%	0.00%
JOY GLOBAL INC	JOYG	0.07%	14.25%	0.01%	0.80%	0.00%
JPMORGAN CHASE & CO	JPM	1.37%	7.62%	0.10%	2.18%	0.03%
NORDSTROM INC	JWN	0.08%	11.15%	0.01%	1.86%	0.00%
KELLOGG CO	K	0.16%	8.75%	0.01%	2.92%	0.00%
KEYCORP	KEY	0.06%	4.75%	0.00%	1.16%	0.00%
KRAFT FOODS INC-CLASS A	KFT	0.49%	9.58%	0.05%	3.46%	0.02%
KIMCO REALTY CORP	KIM	0.06%	7.76%	0.00%	3.66%	0.00%
KLA-TENCOR CORPORATION	KLAC	0.06%	10.00%	0.01%	2.31%	0.00%
KIMBERLY-CLARK CORP	KMB	0.21%	6.83%	0.01%	4.08%	0.01%
CARMAX INC	KMX	0.05%	13.76%	0.01%	na	na
COCA-COLA CO/THE	KO	1.22%	8.33%	0.10%	2.79%	0.03%
KROGER CO	KR	0.12%	7.91%	0.01%	1.75%	0.00%
KOHL'S CORP	KSS	0.12%	13.73%	0.02%	1.88%	0.00%
LOEWS CORP	L	0.14%	na	na	0.59%	na
LEGGETT & PLATT INC	LEG	0.03%	20.00%	0.01%	4.18%	0.00%
LENNAR CORP-A	LEN	0.02%	8.00%	0.00%	0.83%	0.00%
LABORATORY CRP OF AMER HLDGS	LH	0.08%	12.28%	0.01%	0.00%	0.00%
LIFE TECHNOLOGIES CORP	LIFE	0.07%	11.33%	0.01%	0.00%	0.00%
L-3 COMMUNICATIONS HOLDINGS	LLL	0.07%	7.87%	0.01%	2.18%	0.00%
LINEAR TECHNOLOGY CORP	LLTC	0.06%	9.67%	0.01%	2.71%	0.00%
ELI LILLY & CO	LLY	0.36%	na	na	5.09%	na
LEGG MASON INC	LM	0.04%	9.67%	0.00%	0.93%	0.00%
LOCKHEED MARTIN CORP	LMT	0.22%	8.79%	0.02%	3.94%	0.01%
LINCOLN NATIONAL CORP	LNC	0.07%	10.33%	0.01%	0.91%	0.00%
LORILLARD INC	LO	0.13%	9.50%	0.01%	4.53%	0.01%
LOWE'S COS INC	LOW	0.25%	15.22%	0.04%	2.04%	0.01%
LSI CORP	LSI	0.04%	14.50%	0.01%	na	na
LIMITED BRANDS INC	LTD	0.10%	14.25%	0.01%	1.85%	0.00%

		[7]	[8]	[9]	[10]	[11]
Name	Ticker	Weight in Index	Long-Term Growth Est.	Cap-Weighted Long-Term Growth Est.	Estimated Dividend Yield	Cap-Weighted Dividend Yield
LEUCADIA NATIONAL CORP	LUK	0.07%	na	na	na	na
SOUTHWEST AIRLINES CO	LUV	0.07%	8.33%	0.01%	0.12%	0.00%
LEXMARK INTERNATIONAL INC-A	LXK	0.02%	na	na	0.00%	na
MACY'S INC	M	0.10%	7.27%	0.01%	1.24%	0.00%
MASTERCARD INC-CLASS A	MA	0.28%	19.58%	0.05%	0.21%	0.00%
MARRIOTT INTERNATIONAL-CL A	MAR	0.11%	13.16%	0.01%	0.93%	0.00%
MASCO CORP	MAS	0.04%	12.50%	0.01%	2.11%	0.00%
MATTEL INC	MAT	0.07%	8.50%	0.01%	3.38%	0.00%
MCDONALD'S CORP	MCD	0.67%	10.44%	0.07%	3.05%	0.02%
MICROCHIP TECHNOLOGY INC	MCHP	0.06%	12.00%	0.01%	3.56%	0.00%
MCKESSON CORP	MCK	0.17%	11.00%	0.02%	0.85%	0.00%
MOODY'S CORP	MCO	0.07%	11.33%	0.01%	1.18%	0.00%
MEDTRONIC INC	MDT	0.35%	9.28%	0.03%	2.40%	0.01%
MASSEY ENERGY CO	MEE	0.05%	na	na	0.38%	na
METLIFE INC	MET	0.37%	10.43%	0.04%	2.18%	0.01%
MCGRAW-HILL COMPANIES INC	MHP	0.10%	9.67%	0.01%	2.39%	0.00%
MEDCO HEALTH SOLUTIONS INC	MHS	0.19%	16.88%	0.03%	0.00%	0.00%
MARSHALL & ILSLEY CORP	MI	0.03%	na	na	0.50%	na
MEAD JOHNSON NUTRITION CO	MJN	0.11%	10.75%	0.01%	1.45%	0.00%
MCCORMICK & CO-NON VGT SHRS	MKC	0.05%	8.75%	0.00%	2.23%	0.00%
MARSH & MCLENNAN COS	MMC	0.13%	10.67%	0.01%	2.81%	0.00%
MOTOROLA MOBILITY HOLDINGS I	MMI	0.06%	13.00%	0.01%	0.00%	0.00%
3M CO	MMM	0.53%	11.67%	0.06%	2.36%	0.01%
ALTRIA GROUP INC	MO	0.47%	7.67%	0.04%	5.65%	0.03%
MOLEX INC	MOLX	0.02%	11.67%	0.00%	2.46%	0.00%
MONSANTO CO	MON	0.30%	14.28%	0.04%	1.64%	0.00%
MERCK & CO. INC.	MRK	0.90%	4.99%	0.05%	4.15%	0.04%
MARATHON OIL CORP	MRO	0.31%	3.01%	0.01%	1.87%	0.01%
MORGAN STANLEY	MS	0.30%	12.05%	0.04%	0.92%	0.00%
MICROSOFT CORP	MSFT	1.68%	11.31%	0.19%	2.29%	0.04%
MOTOROLA SOLUTIONS INC	MSI	0.13%	na	na	0.00%	na
M & T BANK CORP	MTB	0.09%	7.00%	0.01%	3.17%	0.00%
MICRON TECHNOLOGY INC	MU	0.08%	10.94%	0.01%	0.00%	0.00%
MURPHY OIL CORP	MUR	0.11%	na	na	1.62%	na
MEADWESTVACO CORP	MWV	0.05%	10.00%	0.00%	2.94%	0.00%
MONSTER WORLDWIDE INC	MWW	0.02%	15.50%	0.00%	0.00%	0.00%
MYLAN INC	MYL	0.08%	13.17%	0.01%	0.19%	0.00%
NOBLE ENERGY INC	NBL	0.13%	12.00%	0.02%	0.78%	0.00%
NABORS INDUSTRIES LTD	NBR	0.06%	10.00%	0.01%	0.00%	0.00%
NASDAQ OMX GROUP/THE	NDAQ	0.04%	12.50%	0.00%	0.00%	0.00%
NOBLE CORP	NE	0.08%	13.67%	0.01%	1.50%	0.00%
NEXTERA ENERGY INC	NEE	0.19%	5.53%	0.01%	3.72%	0.01%
NEWMONT MINING CORP	NEM	0.22%	6.00%	0.01%	1.31%	0.00%
NETFLIX INC	NFLX	0.11%	31.09%	0.04%	0.00%	0.00%
NEWFIELD EXPLORATION CO	NFX	0.08%	10.10%	0.01%	0.00%	0.00%
NISOURCE INC	NI	0.05%	8.40%	0.00%	4.53%	0.00%
NIKE INC -CL B	NKE	0.26%	12.55%	0.03%	1.43%	0.00%
NORTHROP GRUMMAN CORP	NOC	0.15%	10.29%	0.02%	2.98%	0.00%
NATIONAL OILWELL VARCO INC	NOV	0.24%	10.70%	0.03%	0.58%	0.00%
NRG ENERGY INC	NRG	0.05%	5.00%	0.00%	0.00%	0.00%
NORFOLK SOUTHERN CORP	NSC	0.21%	14.55%	0.03%	2.16%	0.00%
NATIONAL SEMICONDUCTOR CORP	NSM	0.05%	9.50%	0.00%	1.55%	0.00%
NETAPP INC	NTAP	0.16%	17.60%	0.03%	0.00%	0.00%
NORTHERN TRUST CORP	NTRS	0.09%	4.78%	0.00%	2.24%	0.00%
NORTHEAST UTILITIES	NU	0.05%	7.24%	0.00%	3.14%	0.00%
NUCOR CORP	NUE	0.11%	5.00%	0.01%	3.42%	0.00%
NVIDIA CORP	NVDA	0.10%	16.45%	0.02%	0.00%	0.00%
NOVELLUS SYSTEMS INC	NVLS	0.03%	11.50%	0.00%	0.00%	0.00%
NEWELL RUBBERMAID INC	NWL	0.04%	9.67%	0.00%	1.66%	0.00%
NEWS CORP-CL A	NWSA	0.27%	13.58%	0.04%	0.83%	0.00%
NYSE EURONEXT	NYX	0.08%	10.00%	0.01%	3.30%	0.00%
OWENS-ILLINOIS INC	OI	0.04%	10.50%	0.00%	0.00%	0.00%
ONEOK INC	OKE	0.06%	6.30%	0.00%	2.91%	0.00%
OMNICOM GROUP	OMC	0.10%	9.65%	0.01%	2.14%	0.00%
ORACLE CORP	ORCL	1.38%	13.97%	0.19%	0.52%	0.01%
O'REILLY AUTOMOTIVE INC	ORLY	0.07%	13.80%	0.01%	0.00%	0.00%
OCCIDENTAL PETROLEUM CORP	OXY	0.70%	9.44%	0.07%	1.63%	0.01%
PAYCHEX INC	PAYX	0.09%	11.50%	0.01%	3.84%	0.00%
PEOPLE'S UNITED FINANCIAL	PBCT	0.04%	7.67%	0.00%	4.71%	0.00%
PITNEY BOWES INC	PBI	0.04%	na	na	6.20%	na
PACCAR INC	PCAR	0.15%	13.00%	0.02%	1.54%	0.00%
P G & E CORP	PCG	0.14%	5.04%	0.01%	4.23%	0.01%
PLUM CREEK TIMBER CO	PCL	0.05%	2.00%	0.00%	4.15%	0.00%
PRICELINE.COM INC	PCLN	0.20%	21.25%	0.04%	0.00%	0.00%
PRECISION CASTPARTS CORP	PCP	0.18%	10.90%	0.02%	0.08%	0.00%

		[7]	[8]	[9]	[10]	[11]
Name	Ticker	Weight in Index	Long-Term Growth Est.	Cap-Weighted Long-Term Growth Est.	Estimated Dividend Yield	Cap-Weighted Dividend Yield
METROPCS COMMUNICATIONS INC	PCS	0.05%	23.29%	0.01%	0.00%	0.00%
PATTERSON COS INC	PDCO	0.03%	12.56%	0.00%	0.75%	0.00%
PUBLIC SERVICE ENTERPRISE GP	PEG	0.14%	4.00%	0.01%	4.11%	0.01%
PEPSICO INC	PEP	0.90%	7.83%	0.07%	2.86%	0.03%
PFIZER INC	PFE	1.35%	2.82%	0.04%	3.72%	0.05%
PRINCIPAL FINANCIAL GROUP	PFG	0.08%	11.97%	0.01%	1.87%	0.00%
PROCTER & GAMBLE CO/THE	PG	1.49%	9.29%	0.14%	2.87%	0.04%
PROGRESS ENERGY INC	PGN	0.11%	4.57%	0.01%	5.23%	0.01%
PROGRESSIVE CORP	PGR	0.11%	7.75%	0.01%	1.73%	0.00%
PARKER HANNIFIN CORP	PH	0.11%	6.00%	0.01%	1.35%	0.00%
PULTEGROUP INC	PHM	0.03%	10.00%	0.00%	0.00%	0.00%
PERKINELMER INC	PKI	0.02%	14.95%	0.00%	1.01%	0.00%
PROLOGIS	PLD	0.08%	10.59%	0.01%	2.73%	0.00%
PALL CORP	PLL	0.05%	12.00%	0.01%	1.16%	0.00%
PHILIP MORRIS INTERNATIONAL	PM	1.02%	10.67%	0.11%	3.86%	0.04%
PNC FINANCIAL SERVICES GROUP	PNC	0.26%	7.12%	0.02%	1.86%	0.00%
PINNACLE WEST CAPITAL	PNW	0.04%	6.00%	0.00%	4.70%	0.00%
PEPCO HOLDINGS INC	POM	0.04%	6.67%	0.00%	5.48%	0.00%
PPG INDUSTRIES INC	PPG	0.11%	9.47%	0.01%	2.60%	0.00%
PPL CORPORATION	PPL	0.13%	3.73%	0.00%	5.00%	0.01%
PRUDENTIAL FINANCIAL INC	PRU	0.25%	12.53%	0.03%	1.96%	0.00%
PUBLIC STORAGE	PSA	0.16%	5.04%	0.01%	2.99%	0.00%
QUANTA SERVICES INC	PWR	0.03%	11.83%	0.00%	na	na
PRAXAIR INC	PX	0.26%	11.03%	0.03%	1.89%	0.00%
PIONEER NATURAL RESOURCES CO	PXD	0.09%	23.68%	0.02%	0.18%	0.00%
QUALCOMM INC	QCOM	0.78%	15.53%	0.12%	1.32%	0.01%
QEP RESOURCES INC	QEP	0.06%	15.00%	0.01%	0.18%	0.00%
RYDER SYSTEM INC	R	0.02%	13.30%	0.00%	1.96%	0.00%
REYNOLDS AMERICAN INC	RAI	0.18%	8.00%	0.01%	5.29%	0.01%
ROWAN COMPANIES INC	RDC	0.04%	13.00%	0.01%	0.00%	0.00%
REGIONS FINANCIAL CORP	RF	0.07%	7.00%	0.00%	0.57%	0.00%
ROBERT HALF INTL INC	RHI	0.03%	12.67%	0.00%	2.01%	0.00%
RED HAT INC	RHT	0.07%	19.67%	0.01%	0.00%	0.00%
POLO RALPH LAUREN CORP	RL	0.06%	12.67%	0.01%	0.64%	0.00%
ROCKWELL AUTOMATION INC	ROK	0.10%	15.00%	0.01%	1.63%	0.00%
ROPER INDUSTRIES INC	ROP	0.06%	14.50%	0.01%	0.57%	0.00%
ROSS STORES INC	ROST	0.08%	12.43%	0.01%	1.00%	0.00%
RANGE RESOURCES CORP	RRC	0.07%	29.00%	0.02%	0.29%	0.00%
RR DONNELLEY & SONS CO	RRD	0.04%	10.00%	0.00%	4.87%	0.00%
REPUBLIC SERVICES INC	RSG	0.10%	11.50%	0.01%	2.59%	0.00%
RADIOSHACK CORP	RSH	0.01%	8.50%	0.00%	1.59%	0.00%
RAYTHEON COMPANY	RTN	0.14%	9.00%	0.01%	3.19%	0.00%
SPRINT NEXTEL CORP	S	0.14%	na	na	0.00%	na
SAIC INC	SAI	0.05%	9.00%	0.00%	na	na
STARBUCKS CORP	SBUX	0.22%	17.20%	0.04%	1.49%	0.00%
SCANA CORP	SCG	0.04%	4.85%	0.00%	4.77%	0.00%
SCHWAB (CHARLES) CORP	SCHW	0.17%	10.25%	0.02%	1.36%	0.00%
SPECTRA ENERGY CORP	SE	0.14%	9.33%	0.01%	3.77%	0.01%
SEALED AIR CORP	SEE	0.03%	6.17%	0.00%	2.04%	0.00%
SEARS HOLDINGS CORP	SHLD	0.06%	10.00%	0.01%	0.00%	0.00%
SHERWIN-WILLIAMS CO/THE	SHW	0.07%	10.39%	0.01%	1.67%	0.00%
SIGMA-ALDRICH	SIAL	0.07%	8.30%	0.01%	1.03%	0.00%
JM SMUCKER CO/THE	SJM	0.07%	7.00%	0.01%	2.30%	0.00%
SCHLUMBERGER LTD	SLB	0.93%	15.12%	0.14%	1.13%	0.01%
SARA LEE CORP	SLE	0.09%	7.25%	0.01%	2.34%	0.00%
SLM CORP	SLM	0.07%	10.00%	0.01%	1.76%	0.00%
SNAP-ON INC	SNA	0.03%	10.00%	0.00%	na	na
SANDISK CORP	SNDK	0.09%	12.50%	0.01%	0.00%	0.00%
SCRIPPS NETWORKS INTER-CL A	SNI	0.05%	12.67%	0.01%	0.60%	0.00%
SOUTHERN CO	SO	0.27%	5.67%	0.02%	4.67%	0.01%
SIMON PROPERTY GROUP INC	SPG	0.28%	6.00%	0.02%	2.75%	0.01%
STAPLES INC	SPLS	0.10%	14.84%	0.01%	2.29%	0.00%
STERICYCLE INC	SRCL	0.06%	16.67%	0.01%	na	na
SEMPRA ENERGY	SRE	0.11%	6.43%	0.01%	3.28%	0.00%
SUNTRUST BANKS INC	STI	0.12%	7.14%	0.01%	0.39%	0.00%
ST JUDE MEDICAL INC	STJ	0.13%	12.54%	0.02%	1.01%	0.00%
STATE STREET CORP	STT	0.18%	6.58%	0.01%	1.35%	0.00%
CONSTELLATION BRANDS INC-A	STZ	0.03%	10.00%	0.00%	0.00%	0.00%
SUNOCO INC	SUN	0.04%	5.00%	0.00%	1.48%	0.00%
SUPERVALU INC	SVU	0.02%	na	na	3.45%	na
STANLEY BLACK & DECKER INC	SWK	0.10%	18.00%	0.02%	2.23%	0.00%
SOUTHWESTERN ENERGY CO	SWN	0.12%	22.63%	0.03%	0.00%	0.00%
SAFEWAY INC	SWY	0.07%	10.24%	0.01%	2.02%	0.00%
STRYKER CORP	SYK	0.19%	12.19%	0.02%	1.06%	0.00%
SYMANTEC CORP	SYM	0.12%	8.78%	0.01%	0.00%	0.00%

		[7]	[8]	[9]	[10]	[11]
Name	Ticker	Weight in Index	Long-Term Growth Est.	Cap-Weighted Long-Term Growth Est.	Estimated Dividend Yield	Cap-Weighted Dividend Yield
SYSCO CORP	SY	0.15%	10.50%	0.02%	3.24%	0.00%
AT&T INC	T	1.49%	5.10%	0.08%	5.46%	0.08%
MOLSON COORS BREWING CO -B	TAP	0.06%	12.00%	0.01%	2.56%	0.00%
TERADATA CORP	TDC	0.07%	13.60%	0.01%	na	na
TECO ENERGY INC	TE	0.03%	6.43%	0.00%	4.42%	0.00%
INTEGRYS ENERGY GROUP INC	TEG	0.03%	9.95%	0.00%	5.23%	0.00%
TERADYNE INC	TER	0.02%	16.00%	0.00%	0.00%	0.00%
TARGET CORP	TGT	0.27%	11.66%	0.03%	2.06%	0.01%
TENET HEALTHCARE CORP	THC	0.02%	10.92%	0.00%	0.00%	0.00%
TITANIUM METALS CORP	TIE	0.03%	na	na	0.00%	na
TIFFANY & CO	TIF	0.08%	14.68%	0.01%	1.46%	0.00%
TJX COMPANIES INC	TJX	0.16%	13.00%	0.02%	1.38%	0.00%
TELLABS INC	TLAB	0.01%	8.50%	0.00%	1.75%	0.00%
TORCHMARK CORP	TMK	0.04%	8.50%	0.00%	0.99%	0.00%
THERMO FISHER SCIENTIFIC INC	TMO	0.20%	13.50%	0.03%	0.00%	0.00%
T ROWE PRICE GROUP INC	TROW	0.13%	12.20%	0.02%	1.93%	0.00%
TRAVELERS COS INC/THE	TRV	0.21%	8.25%	0.02%	2.55%	0.01%
TYSON FOODS INC-CL A	TSN	0.05%	8.50%	0.00%	0.84%	0.00%
TESORO CORP	TSO	0.03%	18.42%	0.01%	0.32%	0.00%
TOTAL SYSTEM SERVICES INC	TSS	0.03%	9.89%	0.00%	1.37%	0.00%
TIME WARNER CABLE	TWC	0.21%	13.35%	0.03%	2.49%	0.01%
TIME WARNER INC	TWX	0.32%	14.59%	0.05%	2.58%	0.01%
TEXAS INSTRUMENTS INC	TXN	0.33%	10.29%	0.03%	1.47%	0.00%
TEXTRON INC	TXT	0.05%	44.96%	0.02%	0.50%	0.00%
TYCO INTERNATIONAL LTD	TYC	0.18%	12.45%	0.02%	2.01%	0.00%
UNITEDHEALTH GROUP INC	UNH	0.42%	12.58%	0.05%	1.09%	0.00%
UNUM GROUP	UNM	0.06%	9.33%	0.01%	1.43%	0.00%
UNION PACIFIC CORP	UNP	0.41%	16.13%	0.07%	1.54%	0.01%
UNITED PARCEL SERVICE-CL B	UPS	0.43%	12.03%	0.05%	2.76%	0.01%
URBAN OUTFITTERS INC	URBN	0.04%	18.46%	0.01%	0.00%	0.00%
US BANCORP	USB	0.39%	7.00%	0.03%	1.92%	0.01%
UNITED TECHNOLOGIES CORP	UTX	0.64%	11.43%	0.07%	2.09%	0.01%
VISA INC-CLASS A SHARES	V	0.34%	19.42%	0.07%	0.72%	0.00%
VARIAN MEDICAL SYSTEMS INC	VAR	0.06%	15.05%	0.01%	0.00%	0.00%
VF CORP	VFC	0.09%	11.20%	0.01%	2.52%	0.00%
VIACOM INC-CLASS B	VIA/B	0.21%	17.09%	0.04%	0.77%	0.00%
VALERO ENERGY CORP	VLO	0.12%	5.17%	0.01%	0.79%	0.00%
VULCAN MATERIALS CO	VMC	0.04%	8.60%	0.00%	2.47%	0.00%
VORNADO REALTY TRUST	VNO	0.14%	3.27%	0.00%	2.78%	0.00%
VERISIGN INC	VRSN	0.05%	14.50%	0.01%	0.00%	0.00%
VENTAS INC	VTR	0.07%	6.41%	0.00%	4.09%	0.00%
VERIZON COMMUNICATIONS INC	VZ	0.83%	5.87%	0.05%	5.33%	0.04%
WALGREEN CO	WAG	0.32%	14.33%	0.05%	1.62%	0.01%
WATERS CORP	WAT	0.07%	14.20%	0.01%	0.00%	0.00%
WESTERN DIGITAL CORP	WDC	0.07%	6.50%	0.00%	0.00%	0.00%
WISCONSIN ENERGY CORP	WEC	0.06%	6.75%	0.00%	3.32%	0.00%
WELLS FARGO & CO	WFC	1.20%	10.00%	0.12%	1.73%	0.02%
WHOLE FOODS MARKET INC	WFM	0.09%	18.05%	0.02%	0.62%	0.00%
MEMC ELECTRONIC MATERIALS	WFR	0.02%	15.00%	0.00%	0.00%	0.00%
WHIRLPOOL CORP	WHR	0.05%	15.00%	0.01%	2.22%	0.00%
WINDSTREAM CORP	WIN	0.05%	na	na	7.43%	na
WELLPOINT INC	WLP	0.23%	10.67%	0.02%	1.28%	0.00%
WASTE MANAGEMENT INC	WM	0.15%	10.40%	0.02%	3.50%	0.01%
WILLIAMS COS INC	WMB	0.15%	14.90%	0.02%	2.06%	0.00%
WAL-MART STORES INC	WMT	1.54%	10.46%	0.16%	2.58%	0.04%
WATSON PHARMACEUTICALS INC	WPI	0.06%	10.57%	0.01%	0.00%	0.00%
WASHINGTON POST-CLASS B	WPO	0.02%	na	na	na	na
WESTERN UNION CO	WU	0.10%	12.46%	0.01%	1.39%	0.00%
WEYERHAEUSER CO	WY	0.09%	5.50%	0.01%	2.81%	0.00%
WYNDHAM WORLDWIDE CORP	WYN	0.05%	6.03%	0.00%	1.72%	0.00%
WYNN RESORTS LTD	WYNN	0.15%	50.18%	0.07%	1.19%	0.00%
UNITED STATES STEEL CORP	X	0.05%	5.00%	0.00%	0.43%	0.00%
XCEL ENERGY INC	XEL	0.10%	5.30%	0.01%	4.18%	0.00%
XL GROUP PLC	XL	0.06%	10.00%	0.01%	1.81%	0.00%
XILINX INC	XLNX	0.07%	11.67%	0.01%	2.04%	0.00%
EXXON MOBIL CORP	XOM	3.28%	4.87%	0.16%	2.17%	0.07%
DENTSPLY INTERNATIONAL INC	XRAY	0.04%	12.33%	0.01%	0.37%	0.00%
XEROX CORP	XRX	0.11%	13.67%	0.02%	1.67%	0.00%
YAHOO! INC	YHOO	0.17%	14.47%	0.02%	0.00%	0.00%
YUM! BRANDS INC	YUM	0.21%	12.63%	0.03%	1.87%	0.00%
ZIONS BANCORPORATION	ZION	0.03%	7.75%	0.00%	0.17%	0.00%
ZIMMER HOLDINGS INC	ZMH	0.10%	10.84%	0.01%	0.00%	0.00%

Notes:

[1] Equals sum of Col. [11]

[2] Equals sum of Col. [9]

[3] Equals $((1 \times (1 + (0.5 \times [2]))) + [2])$

[4] Source: Bloomberg

[5] Equals [3] - [4]

[6] Equals sum of Col. [7] if Col. [8] $\neq$ n/a

[7] Equals weight in S&P 500 based on market capitalization

[8] Source: Bloomberg

[9] Equals Col. [7] x Col. [8] if Col. [8] $\neq$ n/a, otherwise equals n/a

[10] Source: Bloomberg

[11] Equals Col. [7] x Col. [10] if Col. [8] $\neq$ n/a, otherwise equals n/a

R. B. HEVERT
Direct Exhibit
DC P.S.C. - July, 2011

Introduced as:
PEPCO _____ (D) -4

	BETA ANALYSIS																			
	AEP		CNL		EDE		GXP		HE		IDA		PNW		POR		SO		WR	
Week Ended	Price	Return	Price	Return	Price	Return	Price	Return	Price	Return	Price	Return	Price	Return	Price	Return	Price	Return	Price	Return
5/27/2011	38.32	-0.60%	34.56	-0.75%	18.72	-18.86%	20.89	-0.38%	24.61	-3.83%	39.01	-0.56%	44.99	-0.86%	25.72	0.63%	39.80	-1.66%	26.90	-2.36%
5/20/2011	38.55	2.58%	34.82	-0.37%	23.07	0.22%	20.97	-0.38%	25.59	-1.69%	39.23	-1.18%	45.38	0.38%	25.56	-0.51%	40.47	-0.05%	27.55	-1.08%
5/13/2011	37.58	3.44%	34.95	0.20%	23.02	2.13%	21.05	1.49%	26.03	0.12%	39.70	1.28%	45.21	2.40%	25.69	3.17%	40.49	2.51%	27.85	2.77%
5/6/2011	36.33	-0.41%	34.88	-0.63%	22.54	0.45%	20.74	0.78%	26.00	2.00%	39.20	-0.03%	44.15	1.75%	24.90	-0.24%	39.50	1.18%	27.10	-0.40%
4/29/2011	36.48	2.79%	35.10	0.95%	22.44	3.22%	20.58	3.05%	25.49	3.32%	39.21	2.64%	43.39	1.71%	24.96	2.55%	39.04	1.24%	27.21	3.66%
4/22/2011	35.49	0.08%	34.77	0.49%	21.74	0.00%	19.97	-0.50%	24.67	0.12%	38.20	-1.04%	42.66	-0.70%	24.34	1.97%	38.56	0.60%	26.25	0.54%
4/15/2011	35.46	0.42%	34.60	-1.20%	21.74	0.14%	20.07	-2.24%	24.64	-1.28%	38.60	-0.54%	42.96	-0.14%	23.87	-0.83%	38.33	-0.18%	26.11	-0.76%
4/8/2011	35.31	-0.59%	35.02	0.66%	21.71	-0.91%	20.53	0.88%	24.96	-1.27%	38.81	0.96%	43.02	-0.60%	24.07	-0.08%	38.40	0.23%	26.31	-1.61%
4/1/2011	35.52	2.33%	34.79	3.70%	21.91	2.72%	20.35	3.83%	25.28	3.95%	38.44	3.36%	43.28	2.68%	24.09	2.99%	38.31	1.94%	26.74	2.69%
3/25/2011	34.71	2.66%	33.55	2.91%	21.33	2.11%	19.60	3.21%	24.32	3.40%	37.19	0.92%	42.15	1.79%	23.39	-0.21%	37.58	1.57%	26.04	2.12%
3/18/2011	33.81	-5.59%	32.60	-1.42%	20.89	-2.43%	18.99	-2.57%	23.52	-4.08%	36.85	-1.15%	41.41	-4.94%	23.44	-0.55%	37.00	-3.34%	25.50	-1.89%
3/11/2011	35.81	1.36%	33.07	0.46%	21.41	0.66%	19.49	1.35%	24.52	-0.57%	37.28	-0.88%	43.56	0.53%	23.57	0.21%	38.28	0.82%	25.99	0.70%
3/4/2011	35.33	0.14%	32.92	2.68%	21.27	-1.30%	19.23	0.31%	24.66	2.62%	37.61	-0.27%	43.33	3.86%	23.52	2.22%	37.97	-0.24%	25.81	-0.31%
2/25/2011	35.28	-1.34%	32.06	0.98%	21.55	-1.15%	19.17	-2.79%	24.03	-2.08%	37.71	-1.23%	41.72	-0.38%	23.01	1.14%	38.06	0.50%	25.89	-1.45%
2/18/2011	35.76	-0.28%	31.75	0.38%	21.80	0.51%	19.72	-1.30%	24.54	-1.96%	38.18	-0.44%	41.88	-0.14%	22.75	-0.48%	37.87	-0.42%	26.27	1.16%
2/11/2011	35.86	0.67%	31.63	1.44%	21.69	0.84%	19.98	1.47%	25.03	0.32%	38.35	1.37%	41.94	2.19%	22.86	1.28%	38.03	1.85%	25.97	0.93%
2/4/2011	35.62	-0.67%	31.18	-0.42%	21.51	-0.05%	19.69	-0.10%	24.95	0.73%	37.83	0.34%	41.04	0.24%	22.57	0.80%	37.34	-1.14%	25.73	0.35%
1/28/2011	35.86	-1.59%	31.31	0.97%	21.52	-0.14%	19.71	-0.25%	24.77	0.28%	37.70	-0.71%	40.94	-1.68%	22.39	1.73%	37.77	-1.25%	25.64	-0.62%
1/21/2011	36.44	2.79%	31.01	-1.56%	21.55	-0.28%	19.76	-0.05%	24.70	0.20%	37.97	0.21%	41.64	0.29%	22.01	0.00%	38.25	-0.65%	25.80	0.58%
1/14/2011	35.45	-1.53%	31.50	1.74%	21.61	-1.68%	19.77	1.65%	24.65	-0.44%	37.89	1.80%	41.52	-0.17%	22.01	0.41%	38.50	1.10%	25.65	1.06%
1/7/2011	36.00	0.06%	30.96	0.65%	21.98	-0.99%	19.45	0.31%	24.76	8.64%	37.22	0.65%	41.59	0.34%	21.92	1.01%	38.08	-0.39%	25.38	0.87%
12/31/2010	35.98	0.17%	30.76	-0.84%	22.20	0.14%	19.39	-0.67%	22.79	1.51%	36.98	-1.41%	41.45	-0.86%	21.70	-1.72%	38.23	-0.08%	25.16	-0.71%
12/24/2010	35.92	-0.19%	31.02	-0.19%	22.17	0.82%	19.52	1.04%	22.45	0.63%	37.51	-0.21%	41.81	0.72%	22.08	-1.03%	38.26	0.95%	25.34	-0.04%
12/17/2010	35.99	0.98%	31.08	2.24%	21.99	1.62%	19.32	0.26%	22.31	0.27%	37.59	0.24%	41.51	1.59%	22.31	1.92%	37.90	0.21%	25.35	1.73%
12/10/2010	35.64	-0.97%	30.40	-0.72%	21.64	0.14%	19.27	-0.26%	22.25	0.23%	37.50	0.43%	40.86	-0.34%	21.89	0.00%	37.82	-0.79%	24.92	-1.54%
12/3/2010	35.99	0.39%	30.62	-0.33%	21.61	-2.35%	19.32	1.95%	22.20	-0.09%	37.34	2.84%	41.00	1.16%	21.89	3.55%	38.12	0.77%	25.31	0.48%
11/26/2010	35.85	0.28%	30.72	0.29%	22.13	1.61%	18.95	1.83%	22.22	-0.98%	36.31	1.14%	40.53	-0.88%	21.14	0.96%	37.83	-0.63%	25.19	0.52%
11/19/2010	35.75	-2.11%	30.63	-0.20%	21.78	-1.49%	18.61	-1.06%	22.44	0.85%	35.90	-1.21%	40.89	-0.05%	20.94	-1.37%	38.07	-0.05%	25.06	1.25%
11/12/2010	36.52	-3.13%	30.69	-3.22%	22.11	0.41%	18.81	-3.09%	22.25	-4.67%	36.34	-2.47%	40.91	-2.92%	21.23	-1.35%	38.09	-0.99%	24.75	-3.13%
11/5/2010	37.70	0.69%	31.71	1.41%	22.02	4.66%	19.41	2.00%	23.34	3.55%	37.26	1.25%	42.14	2.38%	21.52	2.97%	38.47	1.58%	25.55	0.99%
10/29/2010	37.44	2.02%	31.27	1.20%	21.04	1.64%	19.03	1.55%	22.54	1.58%	36.80	0.33%	41.16	-2.42%	20.90	0.72%	37.87	-1.17%	25.30	1.52%
10/22/2010	36.70	2.11%	30.90	0.32%	20.70	0.15%	18.74	-1.16%	22.19	-1.99%	36.68	1.44%	42.18	1.25%	20.75	0.19%	38.32	1.70%	24.92	0.69%
10/15/2010	35.94	-0.69%	30.80	1.38%	20.67	0.49%	18.96	0.05%	22.64	0.62%	36.16	-0.52%	41.66	0.97%	20.71	0.68%	37.68	-0.08%	24.75	0.32%
10/8/2010	36.19	-0.08%	30.38	1.64%	20.57	1.58%	18.95	-0.11%	22.50	-1.01%	36.35	-0.85%	41.26	-0.94%	20.57	0.93%	37.71	1.53%	24.67	0.69%
10/1/2010	36.22	-0.77%	29.89	1.77%	20.25	1.76%	18.97	0.16%	22.73	0.58%	36.66	5.62%	41.65	1.02%	20.38	1.24%	37.14	-0.93%	24.50	1.74%
9/24/2010	36.50	1.73%	29.37	1.63%	19.90	0.91%	18.94	0.58%	22.60	-2.25%	34.71	-0.40%	41.23	2.16%	20.13	-0.54%	37.49	1.16%	24.08	1.60%
9/17/2010	35.88	-2.05%	28.90	-0.55%	19.72	-0.50%	18.83	-0.69%	23.12	0.13%	34.85	-2.27%	40.36	-0.47%	20.24	0.40%	37.06	-0.13%	23.70	-1.86%
9/10/2010	36.63	1.41%	29.06	-0.27%	19.82	-0.25%	18.96	-0.52%	23.09	-4.47%	35.66	-1.19%	40.55	-1.19%	20.16	-0.88%	37.11	0.32%	24.15	-1.07%
9/3/2010	36.12	1.15%	29.14	1.71%	19.87	-1.97%	19.06	1.98%	24.17	0.67%	36.09	1.21%	41.04	1.74%	20.34	0.49%	36.99	0.05%	24.41	1.58%
8/27/2010	35.71	2.56%	28.65	2.10%	20.27	1.86%	18.69	0.92%	24.01	0.38%	35.66	1.48%	40.34	2.70%	20.24	2.79%	36.97	3.33%	24.03	2.60%
8/20/2010	34.82	-1.97%	28.06	-0.46%	19.90	0.45%	18.52	1.20%	23.92	0.38%	35.14	-0.82%	39.28	-0.56%	19.69	0.00%	35.78	-0.17%	23.42	-1.80%
8/13/2010	35.52	-1.28%	28.19	-2.22%	19.81	-0.40%	18.30	-1.24%	23.83	-0.08%	35.43	-1.72%	39.50	0.41%	19.69	-1.01%	35.84	-0.11%	23.85	-1.97%
8/6/2010	35.98	0.00%	28.83	0.98%	19.89	1.22%	18.53	3.29%	23.85	1.27%	36.05	2.36%	39.34	3.28%	19.89	4.14%	35.88	1.56%	24.33	1.88%
7/30/2010	35.98	0.50%	28.55	-0.73%	19.65	-0.51%	17.94	0.67%	23.55	-1.96%	35.22	-2.03%	38.09	-2.43%	19.10	0.05%	35.33	-1.56%	23.88	0.80%
7/23/2010	35.80	2.99%	28.76	4.13%	19.75	2.28%	17.82	3.60%	24.02	3.22%	35.95	3.51%	39.04	3.17%	19.09	3.02%	35.89	3.19%	23.69	3.68%
7/16/2010	34.76	-0.23%	27.62	-0.93%	19.31	-0.92%	17.20	-2.82%	23.27	-1.31%	34.73	-0.32%	37.84	-0.81%	18.53	-2.78%	34.78	0.20%	22.85	0.62%
7/9/2010	34.84	7.56%	27.88	6.66%	19.49	3.40%	17.70	4.42%	23.58	5.17%	34.84	6.15%	38.15	5.27%	19.06	4.90%	34.71	3.98%	22.71	5.68%
7/2/2010	32.39	-1.82%	26.14	-0.68%	18.85	-0.53%	16.95	-2.08%	22.42	-3.20%	32.82	-2.23%	36.24	-0.98%	18.17	-1.73%	33.38	0.30%	21.49	-2.01%
6/25/2010	32.99	-3.14%	26.32	-2.81%	18.95	-1.04%	17.31	-3.03%	23.16	-0.81%	33.57	-4.03%	36.60	-2.74%	18.49	-5.18%	33.28	-2.43%	21.93	-3.73%
6/18/2010	34.06	4.96%	27.08	4.64%	19.15	4.64%	17.85	4.14%	23.35	4.06%	34.98	6.48%	37.63	5.52%	19.50	4.33%	34.11	3.27%	22.78	4.35%
6/11/2010	32.45	4.27%	25.88	0.82%	18.30	2.12%	17.14	0.41%	22.44	3.51%	32.85	3.01%	35.66	2.65%	18.69	2.02%	33.03	2.80%	21.83	0.69%
6/4/2010	31.12	-2.63%	25.67	-3.02%	17.92	-1.75%	17.07	-2.74%	21.68	-1.28%	31.89	-3.51%	34.74	-1.05%	18.32	-3.12%	32.13	-1.74%	21.68	-1.45%
5/28/2010	31.96	1.59%	26.47	0.76%	18.24	0.66%	17.55	2.09%	21.96	0.37%	33.05	2.16%	35.11	-0.17%	18.91	0.96%	32.70	-2.74%	22.00	0.41%
5/21/2010	31.46	-4.67%	26.27	-4.02%	18.12	-5.77%	17.19	-7.38%	21.88	-5.40%	32.35	-6.50%	35.17	-2.76%	18.73	-4.00%	33.62	-2.47%	21.91	-6.05%
5/14/2010	33.00	3.38%	27.37	5.31%	19.23	5.20%	18.56	2.88%	23.13	4.57%	34.60	3.78%	36.17	2.93%	19.51	2.25%	34.47	1.62%	23.32	4.62%
5/7/2010	31.92	-6.94%	25.99	-5.15%	18.28	-6.30%	18.04	-6.67%	22.12	-5.27%	33.34	-7.59%	35.14	-5.89%	19.08	-4.02%	33.92	-1.85%	22.29	-5.91%

BETA ANALYSIS																				
	AEP		CNL		EDE		GXP		HE		IDA		PNW		POR		SO		WR	
Week Ended	Price	Return	Price	Return	Price	Return	Price	Return	Price	Return	Price	Return	Price	Return	Price	Return	Price	Return	Price	Return
4/30/2010	34.30	0.82%	27.40	-1.08%	19.51	-0.26%	19.33	1.58%	23.35	-2.30%	36.08	-1.15%	37.34	-2.84%	19.88	-1.34%	34.56	-0.49%	23.69	1.67%
4/23/2010	34.02	0.86%	27.70	3.71%	19.56	4.65%	19.03	1.76%	23.90	5.05%	36.50	3.49%	38.43	2.43%	20.15	3.44%	34.73	2.54%	23.30	3.14%
4/16/2010	33.73	-1.58%	26.71	0.75%	18.69	2.35%	18.70	-1.73%	22.75	0.53%	35.27	0.60%	37.52	-1.26%	19.48	-0.71%	33.87	-0.18%	22.59	0.00%
4/9/2010	34.27	-0.64%	26.51	-0.93%	18.26	0.88%	19.03	1.22%	22.63	-0.18%	35.06	-0.17%	38.00	-0.29%	19.62	-0.15%	33.93	1.53%	22.59	0.00%
4/2/2010	34.49	1.17%	26.76	2.02%	18.10	0.78%	18.80	2.68%	22.67	1.89%	35.12	2.24%	38.11	1.49%	19.65	2.93%	33.42	0.97%	22.59	2.87%
3/26/2010	34.09	-1.25%	26.23	-1.43%	17.96	-1.59%	18.31	-3.43%	22.25	-0.22%	34.35	-1.91%	37.55	-0.58%	19.09	-1.70%	33.10	-0.24%	21.96	-1.83%
3/19/2010	34.52	1.23%	26.61	0.11%	18.25	0.77%	18.96	2.49%	22.30	1.87%	35.02	-0.26%	37.77	1.18%	19.42	1.09%	33.18	2.16%	22.37	1.36%
3/12/2010	34.10	-0.44%	26.58	2.11%	18.11	-0.88%	18.50	1.87%	21.89	4.09%	35.11	2.27%	37.33	-1.74%	19.21	0.73%	32.48	0.81%	22.07	1.10%
3/5/2010	34.25	1.87%	26.03	3.13%	18.27	2.01%	18.16	1.97%	21.03	3.24%	34.33	3.94%	37.99	4.34%	19.07	6.00%	32.22	1.42%	21.83	2.01%
2/26/2010	33.62	-1.03%	25.24	-3.88%	17.91	-4.22%	17.81	-2.41%	20.37	2.26%	33.03	0.03%	36.41	-2.57%	17.99	-6.74%	31.77	-1.61%	21.40	-3.52%
2/19/2010	33.97	3.10%	26.26	5.12%	18.70	2.13%	18.25	3.22%	19.92	-0.10%	33.02	4.00%	37.37	5.86%	19.29	1.63%	32.29	3.59%	22.18	4.52%
2/12/2010	32.95	-2.05%	24.98	0.08%	18.31	1.44%	17.68	1.32%	19.94	4.84%	31.75	4.06%	35.30	-0.20%	18.98	-0.37%	31.17	-1.67%	21.22	1.34%
2/5/2010	33.64	-2.91%	24.96	-3.70%	18.05	-1.96%	17.45	-2.30%	19.02	-3.84%	30.51	-2.68%	35.37	-1.26%	19.05	-2.31%	31.70	-0.94%	20.94	-1.83%
1/29/2010	34.65	-2.17%	25.92	0.39%	18.41	-1.07%	17.86	-2.30%	19.78	-6.26%	31.35	-0.60%	35.82	-0.47%	19.50	-1.56%	32.00	-1.66%	21.33	-1.07%
1/22/2010	35.42	-1.64%	25.82	-3.48%	18.61	-1.69%	18.28	-3.18%	21.10	-1.86%	31.54	-3.04%	35.99	-3.07%	19.81	-2.75%	32.54	-2.40%	21.56	-3.06%
1/15/2010	36.01	1.12%	26.75	0.15%	18.93	1.94%	18.88	-2.53%	21.50	1.65%	32.53	0.71%	37.13	0.57%	20.37	1.85%	33.34	1.55%	22.24	2.39%
1/8/2010	35.61	2.36%	26.71	-2.27%	18.57	-0.85%	19.37	-0.10%	21.15	1.20%	32.30	1.10%	36.92	0.93%	20.00	-2.01%	32.83	-1.47%	21.72	0.00%
1/1/2010	34.79	-0.94%	27.33	-1.51%	18.73	0.70%	19.39	-2.07%	20.90	-1.37%	31.95	-2.08%	36.58	-1.43%	20.41	-1.50%	33.32	-0.39%	21.72	-1.41%
12/25/2009	35.12	0.11%	27.75	2.25%	18.60	-0.16%	19.80	-0.55%	21.19	2.71%	32.63	2.97%	37.11	-0.05%	20.72	-0.53%	33.45	-1.01%	22.03	0.69%
12/18/2009	35.08	-1.41%	27.14	1.65%	18.63	-3.27%	19.91	5.40%	20.63	-0.29%	31.69	1.64%	37.13	-1.56%	20.83	-1.79%	33.79	-1.26%	21.88	-0.14%
12/11/2009	35.58	5.30%	26.70	1.68%	19.26	3.38%	18.89	3.11%	20.69	5.03%	31.18	2.90%	37.72	4.11%	21.21	3.56%	34.22	4.23%	21.91	2.67%
12/4/2009	33.79	7.10%	26.26	2.98%	18.63	3.10%	18.32	2.63%	19.70	-1.50%	30.30	2.54%	36.23	3.81%	20.48	5.79%	32.83	3.86%	21.34	4.35%
11/27/2009	31.55	0.90%	25.50	0.39%	18.07	-0.61%	17.85	0.39%	20.00	4.49%	29.55	0.34%	34.90	2.56%	19.36	-0.15%	31.61	0.67%	20.45	1.44%
11/20/2009	31.27	-1.11%	25.40	1.07%	18.18	-0.11%	17.78	-0.61%	19.14	0.00%	29.45	1.13%	34.03	2.41%	19.39	0.78%	31.40	-0.57%	20.16	1.10%
11/13/2009	31.62	1.90%	25.13	2.24%	18.20	-0.66%	17.89	3.11%	19.14	1.38%	29.12	1.08%	33.23	1.19%	19.24	1.21%	31.58	-0.03%	19.94	1.89%
11/6/2009	31.03	2.68%	24.58	-0.69%	18.32	1.44%	17.35	0.29%	18.88	5.77%	28.81	2.56%	32.84	4.85%	19.01	2.26%	31.59	1.28%	19.57	2.19%
10/30/2009	30.22	-1.91%	24.75	-0.92%	18.06	-1.85%	17.30	-3.35%	17.85	-2.30%	28.09	-2.43%	31.32	-6.45%	18.59	-6.77%	31.19	-4.53%	19.15	-2.74%
10/23/2009	30.81	-1.97%	24.98	-1.89%	18.40	-0.05%	17.90	-2.66%	18.27	-0.38%	28.79	-0.42%	33.48	-1.50%	19.94	-1.34%	32.67	0.52%	19.69	-2.91%
10/16/2009	31.43	2.34%	25.46	-0.43%	18.41	-1.02%	18.39	-0.22%	18.34	-2.29%	28.91	-1.06%	33.99	1.95%	20.21	0.30%	32.50	2.07%	20.28	3.47%
10/9/2009	30.71	1.12%	25.57	4.58%	18.60	3.56%	18.43	3.08%	18.77	4.45%	29.22	3.14%	33.34	5.24%	20.15	4.51%	31.84	0.35%	19.60	2.08%
10/2/2009	30.37	-1.97%	24.45	-1.93%	17.96	-0.28%	17.88	0.11%	17.97	-2.02%	28.33	-0.74%	31.68	-2.55%	19.28	-3.65%	31.73	-0.53%	19.20	-1.59%
9/25/2009	30.98	-3.37%	24.93	-1.03%	18.01	-0.55%	17.86	-0.61%	18.34	-0.33%	28.54	-1.35%	32.51	-1.57%	20.01	-3.80%	31.90	-0.41%	19.51	-6.20%
9/18/2009	32.06	4.46%	25.19	2.94%	18.11	0.67%	17.97	0.73%	18.40	7.92%	28.93	2.88%	33.03	1.82%	20.80	3.69%	32.03	3.22%	20.80	2.16%
9/11/2009	30.69	-0.97%	24.47	0.87%	17.99	-2.07%	17.84	0.62%	17.05	0.77%	28.12	-0.32%	32.44	0.34%	20.06	2.09%	31.03	-1.24%	20.36	0.99%
9/4/2009	30.99	-2.73%	24.26	-1.06%	18.37	0.11%	17.73	0.00%	16.92	-4.78%	28.21	-2.69%	32.33	-2.68%	19.65	0.10%	31.42	-0.51%	20.16	-2.37%
8/28/2009	31.86	1.17%	24.52	-1.68%	18.35	-1.40%	17.73	-1.72%	17.77	0.40%	28.99	-0.41%	33.22	-0.57%	19.63	-0.56%	31.58	0.22%	20.65	0.93%
8/21/2009	31.49	1.22%	24.94	2.00%	18.61	0.54%	18.04	2.79%	17.70	-1.61%	29.11	3.34%	33.41	2.27%	19.74	3.35%	31.51	0.13%	20.46	0.20%
8/14/2009	31.11	-0.26%	24.45	-0.37%	18.51	0.65%	17.55	0.92%	17.99	2.16%	28.17	0.00%	32.67	1.24%	19.10	2.85%	31.47	-0.13%	20.42	0.64%
8/7/2009	31.19	0.74%	24.54	3.59%	18.39	0.22%	17.39	9.17%	17.61	-1.45%	28.17	1.62%	32.27	0.97%	18.57	-2.42%	31.51	0.35%	20.29	3.15%
7/31/2009	30.96	0.06%	23.69	-1.04%	18.35	-1.40%	15.93	0.44%	17.87	3.59%	27.72	2.63%	31.96	-1.33%	19.03	1.71%	31.40	-3.77%	19.67	-1.60%
7/24/2009	30.94	3.83%	23.94	5.84%	18.61	7.08%	15.86	1.99%	17.25	-1.15%	27.01	3.88%	32.39	6.34%	18.71	-5.27%	32.63	3.65%	19.99	4.33%
7/17/2009	29.80	4.45%	22.62	3.19%	17.38	3.08%	15.55	5.00%	17.45	-1.47%	26.00	4.08%	30.46	3.46%	19.75	3.57%	31.48	2.54%	19.16	5.74%
7/10/2009	28.53	0.88%	21.92	-1.39%	16.86	2.37%	14.81	-2.63%	17.71	-6.99%	24.98	-2.57%	29.44	-0.61%	19.07	-1.04%	30.70	-1.00%	18.12	-2.69%
7/3/2009	28.28	-1.15%	22.23	1.93%	16.47	-0.72%	15.21	-1.43%	19.04	2.20%	25.64	-1.38%	29.62	-0.77%	19.27	-1.73%	31.01	-2.79%	18.62	1.03%
6/26/2009	28.61	0.85%	21.81	-2.20%	16.59	2.47%	15.43	-0.06%	18.63	-0.21%	26.00	2.20%	29.85	2.79%	19.61	-1.26%	31.90	4.21%	18.43	-0.43%
6/19/2009	28.37	1.32%	22.30	0.22%	16.19	-0.92%	15.44	-2.95%	18.67	-3.01%	25.44	0.79%	29.04	-2.45%	19.86	3.55%	30.61	0.20%	18.51	-0.11%
6/12/2009	28.00	4.48%	22.25	4.46%	16.34	0.68%	15.91	2.32%	19.25	2.50%	25.24	3.10%	29.77	5.12%	19.18	2.18%	30.55	5.67%	18.53	1.98%
6/5/2009	26.80	1.75%	21.30	4.11%	16.23	3.57%	15.55	3.19%	18.78	8.87%	24.48	5.20%	28.32	2.42%	18.77	4.34%	28.91	1.76%	18.17	1.79%
5/29/2009	26.34	4.73%	20.46	1.84%	15.67	-0.13%	15.07	0.27%	17.25	2.92%	23.27	3.47%	27.65	5.74%	17.99	3.75%	28.41	2.56%	17.85	6.50%
5/22/2009	25.15	0.84%	20.09	-3.32%	15.69	6.88%	15.03	1.55%	16.76	4.68%	22.49	0.54%	26.15	0.19%	17.34	0.93%	27.70	-1.49%	16.76	-1.18%
5/15/2009	24.94	-4.63%	20.78	-2.21%	14.68	-3.74%	14.80	-2.31%	16.01	-4.02%	22.37	-6.71%	26.10	-7.08%	17.18	-7.53%	28.12	-2.23%	16.96	-6.30%
5/8/2009	26.15	-2.93%	21.25	-0.23%	15.25	1.06%	15.15	4.55%	16.68	8.03%	23.98	-0.21%	28.09	1.37%	18.58	-1.33%	28.76	-0.21%	18.10	1.74%
5/1/2009	26.94	2.98%	21.30	-0.47%	15.09	1.14%	14.49	1.90%	15.44	1.91%	24.03	4.39%	27.71	1.32%	18.83	9.92%	28.82	-2.17%	17.79	3.61%
4/24/2009	26.16	-4.28%	21.40	-4.25%	14.92	-1.13%	14.22	-3.07%	15.15	-8.18%	23.02	-2.87%	27.35	-1.23%	17.13	-1.55%	29.46	-0.61%	17.17	-3.76%
4/17/2009	27.33	3.52%	22.35	0.27%	15.09	-0.20%	14.67	3.82%	16.50	3.97%	23.70	0.21%	27.69	-0.97%	17.40	-0.17%	29.64	-4.05%	17.84	-1.16%
4/10/2009	26.40	0.38%	22.29	0.00%	15.12	1.61%	14.13	4.28%	15.87	9.68%	23.65	-0.55%	27.96	1.19%	17.43	-1.02%	30.89	-0.61%	18.05	0.45%

BETA ANALYSIS																				
	AEP		CNL		EDE		GXP		HE		IDA		PNW		POR		SO		WR	
Week Ended	Price	Return	Price	Return	Price	Return	Price	Return	Price	Return	Price	Return	Price	Return	Price	Return	Price	Return	Price	Return
4/3/2009	26.30	0.11%	22.29	-0.09%	14.88	2.90%	13.55	-1.45%	14.47	3.80%	23.78	0.46%	27.63	4.34%	17.61	2.44%	31.08	1.67%	17.97	2.69%
3/27/2009	26.27	-4.72%	22.31	4.40%	14.46	2.55%	13.75	5.20%	13.94	3.11%	23.67	-0.42%	26.48	1.30%	17.19	-4.23%	30.57	-0.03%	17.50	1.69%
3/20/2009	27.57	9.19%	21.37	6.21%	14.10	10.33%	13.07	11.23%	13.52	1.65%	23.77	7.17%	26.14	7.53%	17.95	6.78%	30.58	12.68%	17.21	8.44%
3/13/2009	25.25	1.77%	20.12	-3.55%	12.78	2.00%	11.75	1.21%	13.30	6.83%	22.18	1.93%	24.31	3.40%	16.81	4.41%	27.14	-3.24%	15.87	1.86%
3/6/2009	24.81	-11.55%	20.86	1.66%	12.53	-9.27%	11.61	-14.25%	12.45	-10.24%	21.76	-10.60%	23.51	-10.47%	16.10	-1.95%	28.05	-7.46%	15.58	-7.81%
2/27/2009	28.05	-4.79%	20.52	3.27%	13.81	-9.97%	13.54	-4.18%	13.87	-14.80%	24.34	0.37%	26.26	-8.53%	16.42	-1.91%	30.31	0.46%	16.90	-1.86%
2/20/2009	29.46	-7.39%	19.87	-9.02%	15.34	-9.45%	14.13	-8.90%	16.28	-23.14%	24.25	-9.92%	28.71	-13.81%	16.74	-8.17%	30.17	-3.89%	17.22	-9.46%
2/13/2009	31.81	-4.24%	21.84	-5.58%	16.94	-6.62%	15.51	-23.75%	21.18	-5.70%	26.92	-6.66%	33.31	-3.64%	18.23	-6.99%	31.39	-6.55%	19.02	-7.85%
2/6/2009	33.22	5.96%	23.13	1.23%	18.14	2.14%	20.34	6.66%	22.46	3.60%	28.84	-0.93%	34.57	3.29%	19.60	0.77%	33.59	0.42%	20.64	2.79%
1/30/2009	31.35	-1.85%	22.85	4.58%	17.76	3.20%	19.07	1.17%	21.68	0.51%	29.11	0.55%	33.47	2.51%	19.45	4.35%	33.45	-3.46%	20.08	2.40%
1/23/2009	31.94	-1.72%	21.85	-2.28%	17.21	0.41%	18.85	-1.41%	21.57	-1.06%	28.95	-1.90%	32.65	0.00%	18.64	-0.69%	34.65	-1.08%	19.61	-2.05%
1/16/2009	32.50	-0.34%	22.36	0.63%	17.14	-1.15%	19.12	-1.14%	21.80	-0.73%	29.51	0.44%	32.65	-0.76%	18.77	0.70%	35.03	-1.41%	20.02	1.78%
1/9/2009	32.61	-4.09%	22.22	-5.57%	17.34	-3.18%	19.34	-2.77%	21.96	-1.57%	29.38	0.65%	32.90	-0.66%	18.64	-4.16%	35.53	-5.18%	19.67	-4.98%
1/2/2009	34.00	5.99%	23.53	6.28%	17.91	5.23%	19.89	6.14%	22.31	3.48%	29.19	0.79%	33.12	6.70%	19.45	4.74%	37.47	4.17%	20.70	7.25%
12/26/2008	32.08	0.53%	22.14	0.05%	17.02	-0.47%	18.74	-2.09%	21.56	-1.69%	28.96	-2.39%	31.04	3.26%	18.57	2.82%	35.97	0.36%	19.30	-0.05%
12/19/2008	31.91	6.97%	22.13	3.22%	17.10	1.73%	19.14	0.90%	21.93	-5.56%	29.67	2.17%	30.06	1.18%	18.06	-0.93%	35.84	-1.38%	19.31	0.57%
12/12/2008	29.83	-0.27%	21.44	-3.60%	16.81	1.88%	18.97	3.66%	23.22	2.74%	29.04	-1.56%	29.71	-1.20%	18.23	-2.88%	36.34	-1.49%	19.20	-1.13%
12/5/2008	29.91	-4.41%	22.24	-5.64%	16.50	-5.93%	18.30	-2.61%	22.60	-17.13%	29.50	-2.96%	30.07	-1.09%	18.77	2.51%	36.89	1.57%	19.42	-4.00%
11/28/2008	31.29	7.86%	23.57	6.27%	17.54	0.52%	18.79	6.64%	27.27	0.70%	30.40	6.55%	30.40	4.86%	18.31	8.86%	36.32	2.05%	20.23	6.31%
11/21/2008	29.01	-6.27%	22.18	2.69%	17.45	-4.80%	17.62	-3.40%	27.08	1.50%	28.53	-2.39%	28.99	-0.82%	16.82	-4.59%	35.59	1.08%	19.03	-4.99%
11/14/2008	30.95	0.26%	21.60	1.31%	18.33	-1.61%	18.24	-0.76%	26.68	1.25%	29.23	3.03%	29.23	-3.91%	17.63	-6.67%	35.21	1.09%	20.03	2.56%
11/7/2008	30.87	-5.39%	21.32	-7.34%	18.63	-3.02%	18.38	-5.45%	26.35	-1.01%	28.37	6.41%	30.42	-3.89%	18.89	-7.94%	34.83	1.43%	19.53	0.21%
10/31/2008	32.63	5.33%	23.01	10.10%	19.21	5.09%	19.44	6.58%	26.62	5.93%	26.66	7.07%	31.65	8.13%	20.52	8.74%	34.34	-0.78%	19.49	11.95%
10/24/2008	30.98	2.08%	20.90	-0.62%	18.28	1.67%	18.24	0.00%	25.13	2.87%	24.90	0.48%	29.27	-4.50%	18.87	1.02%	34.61	3.34%	17.41	0.29%
10/17/2008	30.35	8.39%	21.03	3.14%	17.98	3.10%	18.24	5.98%	24.43	1.83%	24.78	2.86%	30.65	5.91%	18.68	-7.93%	33.49	3.81%	17.36	-6.87%
10/10/2008	28.00	-21.22%	20.39	-17.58%	17.44	-16.56%	17.21	-22.89%	23.99	-13.02%	24.09	-15.06%	28.94	-16.53%	20.29	-14.57%	32.26	-13.16%	18.64	-17.52%
10/3/2008	35.54	-4.36%	24.74	-3.02%	20.90	-6.07%	22.32	-0.58%	27.58	-4.30%	28.36	-7.14%	34.67	-2.61%	23.75	-2.50%	37.15	-3.81%	22.60	-5.16%
9/26/2008	37.16	-2.67%	25.51	-4.46%	22.25	-3.13%	22.45	-3.19%	28.82	1.48%	30.54	-2.74%	35.60	1.69%	24.36	-2.56%	38.62	0.57%	23.83	-0.83%
9/19/2008	38.18	-2.40%	26.70	5.58%	22.97	6.84%	23.19	-0.77%	28.40	8.98%	31.40	2.58%	35.01	-2.51%	25.00	-1.85%	38.40	0.68%	24.03	4.25%
9/12/2008	39.12	4.46%	25.29	3.82%	21.50	5.29%	23.37	2.73%	26.06	5.59%	30.61	3.34%	35.91	4.48%	25.47	4.26%	38.14	2.80%	23.05	5.88%
9/5/2008	37.45	-4.07%	24.36	-3.37%	20.42	-3.22%	22.75	-2.99%	24.68	-6.69%	29.62	-0.60%	34.37	-2.33%	24.43	-4.64%	37.10	-1.09%	21.77	-3.89%
8/29/2008	39.04	0.21%	25.21	-1.68%	21.10	-3.21%	23.45	-1.88%	26.45	2.12%	29.80	-2.30%	35.19	-0.40%	25.62	1.26%	37.51	-0.74%	22.65	-1.61%
8/22/2008	38.96	1.14%	25.64	-1.08%	21.80	0.00%	23.90	-0.42%	25.90	2.82%	30.50	-1.58%	35.33	1.06%	25.30	-0.20%	37.79	0.93%	23.02	0.00%
8/15/2008	38.52	-1.48%	25.92	1.57%	21.80	2.93%	24.00	-3.58%	25.19	-1.60%	30.99	2.62%	34.96	0.87%	25.35	2.01%	37.44	2.38%	23.02	3.46%
8/8/2008	39.10	0.85%	25.52	2.90%	21.18	4.59%	24.89	0.16%	25.60	5.70%	30.20	2.86%	34.66	5.22%	24.85	6.52%	36.57	5.72%	22.25	1.51%
8/1/2008	38.77	-2.24%	24.80	1.39%	20.25	3.42%	24.85	0.65%	24.22	-0.86%	29.36	-1.41%	32.94	5.07%	23.33	1.35%	34.59	-1.54%	21.92	1.62%
7/25/2008	39.66	0.48%	24.46	3.95%	19.58	2.94%	24.69	-1.44%	24.43	1.54%	29.78	1.64%	31.35	-0.25%	23.02	2.04%	35.13	0.83%	21.57	1.79%
7/18/2008	39.47	-1.62%	23.53	-3.96%	19.02	-3.55%	25.05	-3.02%	24.06	-0.66%	29.30	-2.14%	31.43	-1.84%	22.56	-3.26%	34.84	-3.20%	21.19	-4.72%
7/11/2008	40.12	1.42%	24.50	3.11%	19.72	7.12%	25.83	4.66%	24.22	-2.65%	29.94	5.83%	32.02	4.71%	23.32	4.76%	35.99	1.90%	22.24	3.44%
7/4/2008	39.56	-0.05%	23.76	1.63%	18.41	-0.91%	24.68	-2.30%	24.88	0.61%	28.29	-3.08%	30.58	-1.55%	22.26	-1.94%	35.32	2.58%	21.50	-0.05%
6/27/2008	39.58	-4.26%	23.38	-5.54%	18.58	-5.78%	25.26	-4.86%	24.73	-3.25%	29.19	-5.96%	31.06	-3.30%	22.70	-5.38%	34.43	-0.17%	21.51	-5.28%
6/20/2008	41.34	-3.39%	24.75	0.08%	19.72	-1.30%	26.55	-0.19%	25.56	-3.55%	31.04	-2.60%	32.12	-1.86%	23.99	-0.08%	34.49	-1.71%	22.71	-3.24%
6/13/2008	42.79	1.98%	24.73	0.98%	19.98	-0.70%	26.60	3.34%	26.50	-1.01%	31.87	1.46%	32.73	1.11%	24.01	2.26%	35.09	0.49%	23.47	-0.89%
6/6/2008	41.96	-0.87%	24.49	-1.96%	20.12	-2.71%	25.74	-1.87%	26.77	1.48%	31.41	2.45%	32.37	-4.17%	23.48	0.30%	34.92	-3.54%	23.68	-1.33%
5/30/2008	42.33	0.47%	24.98	1.92%	20.68	-1.19%	26.23	0.04%	26.38	0.08%	30.66	0.72%	33.78	-0.38%	23.41	-0.76%	36.20	0.56%	24.00	2.83%
5/23/2008	42.13	-2.95%	24.51	-1.37%	20.93	0.10%	26.22	-0.64%	26.36	-0.23%	30.44	-2.90%	33.91	-0.85%	23.59	-1.91%	36.00	-2.01%	23.34	0.73%
5/16/2008	43.41	-1.05%	24.85	1.39%	20.91	1.31%	26.39	0.84%	26.42	0.65%	31.35	0.32%	34.20	1.39%	24.05	4.20%	36.74	1.24%	23.17	-1.49%
5/9/2008	43.87	-2.71%	24.51	-0.12%	20.64	-2.18%	26.17	-1.36%	26.25	4.42%	31.25	-5.33%	33.73	-2.46%	23.08	-5.68%	36.29	-2.21%	23.52	-1.09%
5/2/2008	45.09																			

BETA ANALYSIS																					
	AEP		CNL		EDE		GXP		HE		IDA		PNW		POR		SO		WR		
Week Ended	Price	Return	Price	Return	Price	Return	Price	Return	Price	Return	Price	Return	Price	Return	Price	Return	Price	Return	Price	Return	
3/7/2008	40.64	-0.68%	21.97	-4.10%	19.55	-4.68%	24.66	-3.03%	22.84	1.69%	29.68	-0.40%	34.74	-2.28%	22.60	-3.13%	34.29	-0.70%	22.25	-2.11%	
2/29/2008	40.92	-3.26%	22.91	-5.45%	20.51	-4.38%	25.43	-5.50%	22.46	-3.48%	29.80	-3.25%	35.55	-3.45%	23.33	0.43%	34.53	-2.79%	22.73	-2.99%	
2/22/2008	42.30	-1.86%	24.23	-1.06%	21.45	-1.97%	26.91	-0.92%	23.27	4.30%	30.80	-2.10%	36.82	0.49%	23.23	-3.25%	35.52	-0.73%	23.43	-0.89%	
2/15/2008	43.10	-0.14%	24.49	-3.96%	21.88	-1.71%	27.16	-1.24%	22.31	-0.18%	31.46	-0.06%	36.64	-1.40%	24.01	-0.66%	35.78	0.08%	23.64	-2.48%	
2/8/2008	43.16	-1.82%	25.50	-1.92%	22.26	0.68%	27.50	-2.20%	22.35	-1.59%	31.48	-3.41%	37.16	-2.98%	24.17	-1.95%	35.75	-4.16%	24.24	-1.98%	
2/1/2008	43.96	6.36%	26.00	4.21%	22.11	0.55%	28.12	5.20%	22.71	5.04%	32.59	2.61%	38.30	-1.06%	24.65	4.76%	37.30	3.35%	24.73	7.10%	

BETA ANALYSIS							
Week Ended	SPX			Proxy Group			
	Price	Return	S&P 500 Variance	Avg. Return	Covariance	Raw Beta	Adj. Beta
5/27/2011	1,331.10	-0.16%	0.040%	-2.92%	0.024%	0.598	0.732
5/20/2011	1,333.27	-0.34%	0.040%	-0.21%	0.023%	0.589	0.726
5/13/2011	1,337.77	-0.18%	0.044%	1.95%	0.028%	0.641	0.761
5/6/2011	1,340.20	-1.72%	0.044%	0.44%	0.029%	0.663	0.775
4/29/2011	1,363.61	1.96%	0.052%	2.51%	0.037%	0.710	0.806
4/22/2011	1,337.38	1.34%	0.053%	0.16%	0.037%	0.691	0.794
4/15/2011	1,319.68	-0.64%	0.053%	-0.66%	0.038%	0.706	0.804
4/8/2011	1,328.17	-0.32%	0.053%	-0.23%	0.038%	0.705	0.803
4/1/2011	1,332.41	1.42%	0.053%	3.02%	0.037%	0.700	0.800
3/25/2011	1,313.80	2.70%	0.053%	2.05%	0.037%	0.695	0.797
3/18/2011	1,279.20	-1.92%	0.052%	-2.79%	0.036%	0.692	0.795
3/11/2011	1,304.28	-1.28%	0.051%	0.46%	0.035%	0.681	0.787
3/4/2011	1,321.15	0.10%	0.051%	0.97%	0.035%	0.689	0.793
2/25/2011	1,319.88	-1.72%	0.052%	-0.78%	0.037%	0.697	0.798
2/18/2011	1,343.01	1.04%	0.052%	-0.30%	0.037%	0.707	0.804
2/11/2011	1,329.15	1.39%	0.053%	1.24%	0.038%	0.719	0.813
2/4/2011	1,310.87	2.71%	0.053%	0.01%	0.038%	0.719	0.813
1/28/2011	1,276.34	-0.55%	0.052%	-0.33%	0.039%	0.744	0.829
1/21/2011	1,283.35	-0.76%	0.053%	0.15%	0.039%	0.748	0.832
1/14/2011	1,293.24	1.71%	0.056%	0.39%	0.042%	0.747	0.831
1/7/2011	1,271.50	1.10%	0.056%	1.12%	0.042%	0.746	0.831
12/31/2010	1,257.64	0.07%	0.057%	-0.45%	0.041%	0.728	0.818
12/24/2010	1,256.77	1.03%	0.057%	0.25%	0.042%	0.729	0.820
12/17/2010	1,243.91	0.28%	0.058%	1.11%	0.042%	0.724	0.816
12/10/2010	1,240.40	1.28%	0.058%	-0.38%	0.042%	0.724	0.816
12/3/2010	1,224.71	2.97%	0.057%	0.84%	0.042%	0.727	0.818
11/26/2010	1,189.40	-0.86%	0.056%	0.41%	0.042%	0.749	0.833
11/19/2010	1,199.73	0.04%	0.056%	-0.54%	0.042%	0.752	0.835
11/12/2010	1,199.21	-2.17%	0.056%	-2.46%	0.042%	0.751	0.834
11/5/2010	1,225.85	3.60%	0.056%	2.15%	0.041%	0.739	0.826
10/29/2010	1,183.26	0.02%	0.055%	0.70%	0.041%	0.744	0.829
10/22/2010	1,183.08	0.59%	0.059%	0.47%	0.044%	0.752	0.835
10/15/2010	1,176.19	0.95%	0.059%	0.32%	0.044%	0.755	0.836
10/8/2010	1,165.15	1.65%	0.059%	0.34%	0.044%	0.753	0.835
10/1/2010	1,146.24	-0.21%	0.062%	1.22%	0.047%	0.752	0.835
9/24/2010	1,148.67	2.05%	0.063%	0.66%	0.048%	0.756	0.837
9/17/2010	1,125.59	1.45%	0.063%	-0.80%	0.049%	0.765	0.843
9/10/2010	1,109.55	0.46%	0.064%	-0.81%	0.050%	0.780	0.853
9/3/2010	1,104.51	3.75%	0.065%	0.86%	0.050%	0.766	0.844
8/27/2010	1,064.59	-0.66%	0.063%	2.07%	0.050%	0.795	0.863
8/20/2010	1,071.69	-0.70%	0.063%	-0.37%	0.050%	0.800	0.867
8/13/2010	1,079.25	-3.78%	0.064%	-0.96%	0.051%	0.797	0.864
8/6/2010	1,121.64	1.82%	0.061%	2.00%	0.050%	0.817	0.878
7/30/2010	1,101.60	-0.10%	0.061%	-0.72%	0.050%	0.813	0.875
7/23/2010	1,102.66	3.55%	0.061%	3.28%	0.050%	0.810	0.873
7/16/2010	1,064.88	-1.21%	0.062%	-0.93%	0.050%	0.802	0.868
7/9/2010	1,077.96	5.42%	0.070%	5.32%	0.053%	0.760	0.840
7/2/2010	1,022.58	-5.03%	0.066%	-1.50%	0.049%	0.744	0.830
6/25/2010	1,076.76	-3.65%	0.062%	-2.89%	0.048%	0.770	0.846
6/18/2010	1,117.51	2.37%	0.059%	4.64%	0.045%	0.766	0.844
6/11/2010	1,091.60	2.51%	0.060%	2.23%	0.044%	0.732	0.821
6/4/2010	1,064.88	-2.25%	0.059%	-2.23%	0.043%	0.733	0.822
5/28/2010	1,089.41	0.16%	0.058%	0.61%	0.043%	0.739	0.826
5/21/2010	1,087.69	-4.23%	0.060%	-4.90%	0.045%	0.743	0.829
5/14/2010	1,135.68	2.23%	0.056%	3.65%	0.040%	0.712	0.808
5/7/2010	1,110.88	-6.39%	0.061%	-5.56%	0.044%	0.724	0.816

BETA ANALYSIS							
Week Ended	SPX			Proxy Group			
	Price	Return	S&P 500 Variance	Avg. Return	Covariance	Raw Beta	Adj. Beta
4/30/2010	1,186.69	-2.51%	0.058%	-0.54%	0.037%	0.641	0.761
4/23/2010	1,217.28	2.11%	0.056%	3.11%	0.037%	0.655	0.770
4/16/2010	1,192.13	-0.19%	0.056%	-0.12%	0.037%	0.657	0.772
4/9/2010	1,194.37	1.38%	0.056%	0.13%	0.037%	0.655	0.770
4/2/2010	1,178.10	0.99%	0.056%	1.90%	0.037%	0.659	0.773
3/26/2010	1,166.59	0.58%	0.057%	-1.42%	0.037%	0.653	0.769
3/19/2010	1,159.90	0.86%	0.063%	1.20%	0.038%	0.599	0.733
3/12/2010	1,149.99	0.99%	0.063%	0.99%	0.039%	0.615	0.744
3/5/2010	1,138.70	3.10%	0.081%	2.99%	0.040%	0.498	0.665
2/26/2010	1,104.49	-0.42%	0.092%	-2.37%	0.053%	0.572	0.715
2/19/2010	1,109.17	3.13%	0.098%	3.31%	0.057%	0.584	0.723
2/12/2010	1,075.51	0.87%	0.107%	0.88%	0.071%	0.662	0.775
2/5/2010	1,066.19	-0.72%	0.113%	-2.37%	0.079%	0.701	0.801
1/29/2010	1,073.87	-1.64%	0.117%	-1.68%	0.081%	0.692	0.795
1/22/2010	1,091.76	-3.90%	0.116%	-2.62%	0.080%	0.686	0.791
1/15/2010	1,136.03	-0.78%	0.114%	0.94%	0.078%	0.686	0.791
1/8/2010	1,144.98	2.68%	0.118%	-0.11%	0.078%	0.664	0.776
1/1/2010	1,115.10	-1.01%	0.122%	-1.20%	0.082%	0.670	0.780
12/25/2009	1,126.48	2.18%	0.129%	0.64%	0.087%	0.676	0.784
12/18/2009	1,102.47	-0.36%	0.129%	-0.10%	0.087%	0.673	0.782
12/11/2009	1,106.41	0.04%	0.129%	3.60%	0.087%	0.674	0.783
12/4/2009	1,105.98	1.33%	0.129%	3.47%	0.087%	0.676	0.784
11/27/2009	1,091.49	0.01%	0.131%	1.04%	0.089%	0.682	0.788
11/20/2009	1,091.38	-0.19%	0.156%	0.41%	0.100%	0.643	0.762
11/13/2009	1,093.48	2.26%	0.171%	1.33%	0.104%	0.608	0.739
11/6/2009	1,069.30	3.20%	0.179%	2.26%	0.104%	0.582	0.721
10/30/2009	1,036.19	-4.02%	0.181%	-3.33%	0.105%	0.581	0.721
10/23/2009	1,079.60	-0.74%	0.197%	-1.26%	0.115%	0.586	0.724
10/16/2009	1,087.68	1.51%	0.207%	0.51%	0.114%	0.554	0.702
10/9/2009	1,071.49	4.51%	0.210%	3.21%	0.116%	0.552	0.701
10/2/2009	1,025.21	-1.84%	0.271%	-1.51%	0.173%	0.636	0.758
9/25/2009	1,044.38	-2.24%	0.288%	-1.92%	0.179%	0.623	0.748
9/18/2009	1,068.30	2.45%	0.289%	3.05%	0.179%	0.621	0.747
9/11/2009	1,042.73	2.59%	0.287%	0.11%	0.178%	0.619	0.746
9/4/2009	1,016.40	-1.22%	0.286%	-1.66%	0.178%	0.624	0.749
8/28/2009	1,028.93	0.27%	0.287%	-0.36%	0.180%	0.626	0.751
8/21/2009	1,026.13	2.20%	0.287%	1.42%	0.180%	0.626	0.751
8/14/2009	1,004.09	-0.63%	0.286%	0.77%	0.179%	0.626	0.751
8/7/2009	1,010.48	2.33%	0.286%	1.59%	0.179%	0.626	0.751
7/31/2009	987.48	0.84%	0.287%	-0.07%	0.181%	0.630	0.753
7/24/2009	979.26	4.13%	0.287%	3.05%	0.181%	0.631	0.754
7/17/2009	940.38	6.97%	0.283%	3.37%	0.178%	0.630	0.753
7/10/2009	879.13	-1.93%	0.273%	-1.57%	0.172%	0.629	0.753
7/3/2009	896.42	-2.45%	0.273%	-0.48%	0.171%	0.625	0.750
6/26/2009	918.90	-0.25%	0.272%	0.84%	0.170%	0.626	0.751
6/19/2009	921.23	-2.64%	0.274%	-0.34%	0.172%	0.630	0.753
6/12/2009	946.21	0.65%	0.274%	3.25%	0.173%	0.632	0.755
6/5/2009	940.09	2.28%	0.274%	3.70%	0.172%	0.630	0.753
5/29/2009	919.14	3.62%	0.273%	3.17%	0.170%	0.624	0.749
5/22/2009	887.00	0.47%	0.271%	0.96%	0.168%	0.620	0.747
5/15/2009	882.88	-4.99%	0.272%	-4.68%	0.168%	0.617	0.745
5/8/2009	929.23	5.89%	0.270%	1.18%	0.165%	0.611	0.741
5/1/2009	877.52	1.30%	0.262%	2.45%	0.163%	0.623	0.749
4/24/2009	866.23	-0.39%	0.262%	-3.09%	0.163%	0.621	0.747
4/17/2009	869.60	1.52%	0.262%	0.52%	0.163%	0.621	0.747
4/10/2009	856.56	1.67%	0.266%	1.54%	0.166%	0.623	0.749

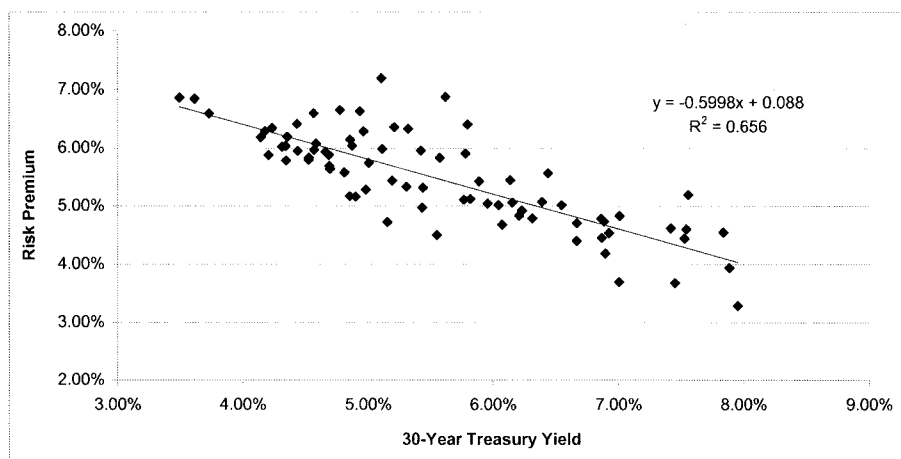
BETA ANALYSIS							
Week Ended	SPX			Proxy Group			
	Price	Return	S&P 500 Variance	Avg. Return	Covariance	Raw Beta	Adj. Beta
4/3/2009	842.50	3.26%	0.266%	1.69%	0.165%	0.620	0.747
3/27/2009	815.94	6.17%	0.268%	0.88%	0.167%	0.622	0.748
3/20/2009	768.54	1.58%	0.258%	8.12%	0.165%	0.638	0.759
3/13/2009	756.55	10.71%	0.260%	1.66%	0.163%	0.628	0.752
3/6/2009	683.38	-7.03%	0.234%	-8.19%	0.159%	0.677	0.785
2/27/2009	735.09	-4.54%	0.228%	-4.19%	0.150%	0.660	0.773
2/20/2009	770.05	-6.87%	0.225%	-10.31%	0.148%	0.657	0.771
2/13/2009	826.84	-4.81%	0.219%	-7.76%	0.137%	0.624	0.750
2/6/2009	868.60	5.17%	0.217%	2.59%	0.130%	0.602	0.735
1/30/2009	825.88	-0.73%	0.212%	1.39%	0.129%	0.605	0.737
1/23/2009	831.95	-2.14%	0.219%	-1.18%	0.133%	0.608	0.739
1/16/2009	850.12	-4.52%	0.219%	-0.20%	0.132%	0.604	0.736
1/9/2009	890.35	-4.45%	0.220%	-3.15%	0.136%	0.619	0.746
1/2/2009	931.80	6.76%	0.217%	5.08%	0.134%	0.618	0.745
12/26/2008	872.80	-1.70%	0.209%	0.03%	0.128%	0.614	0.743
12/19/2008	887.88	0.93%	0.209%	0.89%	0.128%	0.615	0.743
12/12/2008	879.73	0.42%	0.209%	-0.38%	0.129%	0.615	0.744
12/5/2008	876.07	-2.25%	0.209%	-3.97%	0.129%	0.619	0.746
11/28/2008	896.24	12.03%	0.210%	5.06%	0.130%	0.618	0.745
11/21/2008	800.03	-8.39%	0.181%	-2.20%	0.116%	0.645	0.763
11/14/2008	873.29	-6.20%	0.170%	-0.34%	0.114%	0.669	0.780
11/7/2008	930.99	-3.90%	0.165%	-2.60%	0.114%	0.693	0.795
10/31/2008	968.75	10.49%	0.164%	6.81%	0.112%	0.683	0.789
10/24/2008	876.77	-6.78%	0.140%	0.66%	0.097%	0.693	0.795
10/17/2008	940.55	4.60%	0.135%	2.02%	0.100%	0.742	0.828
10/10/2008	899.22	-18.20%	0.131%	-16.81%	0.100%	0.762	0.841
10/3/2008	1,099.23	-9.38%	0.073%	-3.95%	0.045%	0.615	0.743
9/26/2008	1,213.01	-3.35%	0.059%	-1.58%	0.040%	0.681	0.788
9/19/2008	1,255.08	0.27%	0.058%	2.14%	0.039%	0.685	0.790
9/12/2008	1,251.70	0.76%	0.059%	4.26%	0.040%	0.682	0.788
9/5/2008	1,242.31	-3.16%	0.060%	-3.29%	0.040%	0.668	0.779
8/29/2008	1,282.83	-0.73%	0.059%	-0.82%	0.039%	0.655	0.770
8/22/2008	1,292.20	-0.46%	0.059%	0.27%	0.039%	0.656	0.770
8/15/2008	1,298.20	0.15%	0.060%	0.92%	0.038%	0.640	0.760
8/8/2008	1,296.32	2.86%	0.060%	3.60%	0.038%	0.639	0.760
8/1/2008	1,260.31	0.20%	0.059%	0.74%	0.038%	0.654	0.769
7/25/2008	1,257.76	-0.23%	0.059%	1.35%	0.038%	0.649	0.766
7/18/2008	1,260.68	1.71%	0.063%	-2.80%	0.043%	0.675	0.783
7/11/2008	1,239.49	-1.85%	0.063%	3.43%	0.044%	0.702	0.801
7/4/2008	1,262.90	-1.21%	0.063%	-0.51%	0.045%	0.725	0.816
6/27/2008	1,278.38	-3.00%	0.063%	-4.38%	0.046%	0.720	0.813
6/20/2008	1,317.93	-3.10%	0.062%	-1.78%	0.043%	0.701	0.801
6/13/2008	1,360.03	-0.05%	0.061%	0.90%	0.044%	0.719	0.813
6/6/2008	1,360.68	-2.83%	0.062%	-1.22%	0.044%	0.720	0.814
5/30/2008	1,400.38	1.78%	0.061%	0.43%	0.045%	0.748	0.832
5/23/2008	1,375.93	-3.47%	0.061%	-1.20%	0.046%	0.756	0.837
5/16/2008	1,425.35	2.67%	0.058%	0.88%	0.045%	0.777	0.851
5/9/2008	1,388.28	-1.81%	0.057%	-1.87%	0.045%	0.783	0.856
5/2/2008	1,413.90	1.15%	0.057%	1.19%	0.044%	0.781	0.854
4/25/2008	1,397.84	0.54%	0.057%	-0.67%	0.044%	0.777	0.851
4/18/2008	1,390.33	4.31%	0.057%	3.05%	0.044%	0.778	0.852
4/11/2008	1,332.83	-2.74%	0.054%	-0.05%	0.042%	0.774	0.850
4/4/2008	1,370.40	4.20%	0.053%	3.06%	0.042%	0.798	0.866
3/28/2008	1,315.22	-1.07%	0.050%	-2.25%	0.040%	0.798	0.865
3/21/2008	1,329.51	3.21%	0.050%	2.98%	0.039%	0.793	0.862
3/14/2008	1,288.14	-0.40%	0.050%	0.83%	0.040%	0.805	0.870

BETA ANALYSIS							
Week Ended	SPX			Proxy Group			
	Price	Return	S&P 500 Variance	Avg. Return	Covariance	Raw Beta	Adj. Beta
3/7/2008	1,293.37	-2.80%	0.050%	-1.94%	0.040%	0.800	0.867
2/29/2008	1,330.63	-1.66%	0.049%	-3.41%	0.039%	0.796	0.864
2/22/2008	1,353.11	0.23%	0.052%	-0.80%	0.040%	0.771	0.847
2/15/2008	1,349.99	1.40%	0.052%	-1.17%	0.040%	0.772	0.848
2/8/2008	1,331.29	-4.60%	0.052%	-2.13%	0.041%	0.781	0.854
2/1/2008	1,395.42	4.87%	0.048%	3.81%	0.039%	0.805	0.870

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BOND YIELD PLUS RISK PREMIUM			
	[1]	[2]	[3]
Quarter	Average Authorized Electric ROE	Average 30-Yr. Treasury Yield	Risk Premium (ROE-Treasury Yield)
1992.1	12.38%	7.84%	4.55%
1992.2	11.83%	7.88%	3.94%
1992.3	12.03%	7.42%	4.62%
1992.4	12.14%	7.54%	4.60%
1993.1	11.84%	7.01%	4.83%
1993.2	11.64%	6.86%	4.78%
1993.3	11.15%	6.23%	4.92%
1993.4	11.04%	6.21%	4.84%
1994.1	11.07%	6.66%	4.40%
1994.2	11.13%	7.45%	3.68%
1994.3	12.75%	7.55%	5.20%
1994.4	11.24%	7.95%	3.29%
1995.1	11.96%	7.52%	4.44%
1995.2	11.32%	6.87%	4.45%
1995.3	11.37%	6.66%	4.71%
1995.4	11.58%	6.14%	5.45%
1996.1	11.46%	6.39%	5.07%
1996.2	11.46%	6.92%	4.54%
1996.3	10.70%	7.00%	3.70%
1996.4	11.56%	6.54%	5.02%
1997.1	11.08%	6.90%	4.18%
1997.2	11.62%	6.88%	4.73%
1997.3	12.00%	6.44%	5.56%
1997.4	11.06%	6.04%	5.02%
1998.1	11.31%	5.89%	5.43%
1998.2	12.20%	5.79%	6.41%
1998.3	11.65%	5.32%	6.33%
1998.4	12.30%	5.11%	7.20%
1999.1	10.40%	5.43%	4.97%
1999.2	10.94%	5.82%	5.12%
1999.3	10.75%	6.07%	4.68%
1999.4	11.10%	6.31%	4.79%
2000.1	11.21%	6.15%	5.06%
2000.2	11.00%	5.95%	5.05%
2000.3	11.68%	5.78%	5.90%
2000.4	12.50%	5.62%	6.88%
2001.1	11.38%	5.42%	5.96%
2001.2	10.88%	5.77%	5.11%
2001.3	10.76%	5.44%	5.32%
2001.4	11.57%	5.21%	6.36%
2002.1	10.05%	5.55%	4.50%
2002.2	11.41%	5.57%	5.83%
2002.3	11.25%	4.96%	6.29%
2002.4	11.57%	4.93%	6.63%
2003.1	11.43%	4.78%	6.65%
2003.2	11.16%	4.57%	6.60%
2003.3	9.88%	5.15%	4.72%
2003.4	11.09%	5.11%	5.98%
2004.1	11.00%	4.86%	6.14%
2004.2	10.64%	5.31%	5.33%
2004.3	10.75%	5.01%	5.74%
2004.4	10.91%	4.87%	6.04%
2005.1	10.56%	4.69%	5.87%
2005.2	10.13%	4.34%	5.78%
2005.3	10.85%	4.43%	6.41%
2005.4	10.59%	4.66%	5.93%
2006.1	10.38%	4.69%	5.69%
2006.2	10.63%	5.19%	5.44%
2006.3	10.06%	4.90%	5.16%
2006.4	10.33%	4.70%	5.64%
2007.1	10.39%	4.81%	5.58%
2007.2	10.27%	4.98%	5.28%
2007.3	10.02%	4.85%	5.16%
2007.4	10.36%	4.53%	5.83%
2008.1	10.37%	4.34%	6.03%
2008.2	10.54%	4.57%	5.97%
2008.3	10.38%	4.44%	5.95%
2008.4	10.36%	3.49%	6.86%
2009.1	10.46%	3.62%	6.85%
2009.2	10.58%	4.23%	6.34%
2009.3	10.46%	4.18%	6.28%
2009.4	10.54%	4.35%	6.19%
2010.1	10.66%	4.59%	6.08%
2010.2	10.08%	4.20%	5.87%
2010.3	10.32%	3.73%	6.59%
2010.4	10.33%	4.14%	6.18%
2011.1	10.32%	4.53%	5.80%
2011.2	10.33%	4.31%	6.02%
AVERAGE	11.03%	5.57%	5.47%
MEDIAN	11.02%	5.37%	5.51%



SUMMARY OUTPUT

Regression Statistics	
Multiple R	0.80996605
R Square	0.656045002
Adjusted R Square	0.651519278
Standard Error	0.004907308
Observations	78

ANOVA					
	df	SS	MS	F	Significance F
Regression	1	0.003490859	0.003490859	144.9591383	2.72789E-19
Residual	76	0.001830207	2.40817E-05		
Total	77	0.005321066			

	Coefficients	Standard Error	t Stat	P-value	Lower 95%	Upper 95%	Lower 95.0%	Upper 95.0%
Intercept	0.088037347	0.002827666	31.13427887	5.18963E-45	0.082405562	0.09366913	0.082405562	0.093669133
X Variable 1	-0.599781768	0.049816184	-12.03989777	2.72789E-19	-0.698999297	-0.50056424	-0.698999297	-0.50056424

	[7]	[8]	[9]
30-year Treasury Yield	Risk-Free Rate	Risk Premium	ROE
30-day average as of 5/31/2011 [4]	4.34%	6.20%	10.54%
Blue Chip Consensus Forecast (2010-2011) [5]	4.88%	5.87%	10.76%
Blue Chip Consensus Forecast (2012 - 2021) [6]	5.45%	5.53%	10.98%
MEAN	4.89%	5.87%	10.76%

Notes:

[1] Source: Regulatory Research Associates, *Rate Case Statistics*, accessed June 13, 2011

[2] Source: Bloomberg Professional; average of last trading day of each month in a quarter

[3] Equals Col. [1] - Col. [2]

[4] Source: Bloomberg

[5] Blue Chip Financial Forecasts, Vol. 30, No. 5, May 1, 2011, at 2

[6] Blue Chip Financial forecasts, Vol 29, No. 12, December 1, 2010, p. 14

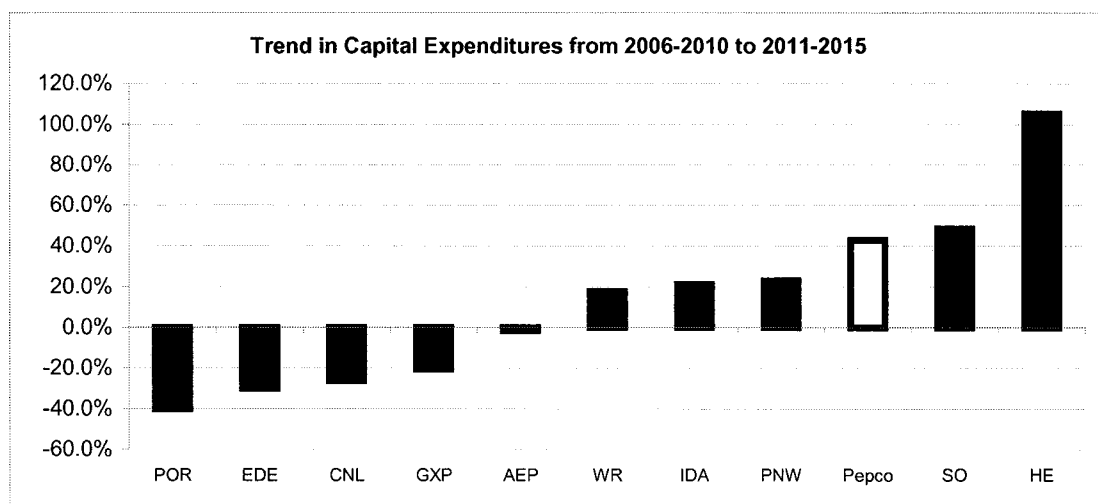
[7] See notes [4], [5] & [6]

[8] Equals intercept + regression coefficient x (Col. [7])

[9] Equals Col. [7] + Col. [8]

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(2011-2015 CapEx)/(2006-2010 CapEx)		
Company		Trend
Portland General	POR	-40.00%
Empire District Electric	EDE	-30.06%
Cleco Corp.	CNL	-26.34%
Great Plains Energy	GXP	-20.75%
American Electric Power	AEP	-1.70%
Westar Energy	WR	17.69%
IDACORP, Inc.	IDA	21.28%
Pinnacle West Capital	PNW	23.04%
Potomac Electric Power Co.	Pepco	42.88%
Southern Company	SO	48.48%
Hawaiian Electric	HE	105.37%
Average (ex. Pepco)		9.70%

Notes:

[1] Pepco capital expenditures are projected from 2011-2015; however, Value Line only projects capital expenditures for 2011, 2012 and 2014-2016. The 2013 estimate is an average of 2012 and 2014. To calculate 2014 and 2015 projected capital expenditures for the proxy group, I annualized Value Line's 2014-2016 projections.

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FLOTATION COST ADJUSTMENT

Flotation Costs (two most recent common stock issuances per company, if available)

Issuing Entity	Date	Shares Issued	Offering Price	Underwriting Discount	Offering Expense	Net Proceeds Per Share	Total Flotation Costs	Gross Equity Issue Before Costs	Net Proceeds	Flotation Cost Percentage
Open Market Issuances										
Pepco Holdings, Inc.	11/5/2008	16,100,000	\$16.50	\$0.6188	\$200,000	\$15.869	\$10,161,875	\$265,650,000	\$255,488,125	3.825%
Pepco Holdings, Inc.	9/9/2004	14,950,000	\$19.25	\$0.6738	\$200,000	\$18.563	\$10,273,310	\$287,787,500	\$277,514,190	3.570%
American Electric Power	4/1/2009	69,000,000	\$24.50	\$0.7350	\$400,000	\$23.759	\$51,115,000	\$1,690,500,000	\$1,639,385,000	3.024%
American Electric Power	2/27/2003	57,500,000	\$20.95	\$0.6285	\$550,000	\$20.312	\$36,688,750	\$1,204,625,000	\$1,167,936,250	3.046%
Cleco Corp.	8/14/2006	6,900,000	\$23.75	\$0.8900	\$225,000	\$22.827	\$6,366,000	\$163,875,000	\$157,509,000	3.885%
Cleco Corp.	11/9/2004	2,000,000	\$18.50	\$0.6475	\$200,000	\$17.753	\$1,495,000	\$37,000,000	\$35,505,000	4.041%
Empire District Electric	12/6/2007	3,450,000	\$23.00	\$0.9775	\$250,000	\$21.950	\$3,622,375	\$79,350,000	\$75,727,625	4.565%
Empire District Electric	6/15/2006	3,795,000	\$20.25	\$0.8600	\$250,000	\$19.324	\$3,513,700	\$76,848,750	\$73,335,050	4.572%
Great Plains Energy Inc.	5/12/2009	11,500,000	\$14.00	\$0.4900	\$500,000	\$13.467	\$6,135,000	\$161,000,000	\$154,865,000	3.811%
Great Plains Energy Inc.	5/17/2006	7,002,450	\$27.50	\$0.8938	\$500,000	\$26.535	\$6,758,790	\$192,567,375	\$185,808,585	3.510%
Hawaiian Electric	12/3/2008	5,750,000	\$23.00	\$0.8625	\$300,000	\$22.085	\$5,259,375	\$132,250,000	\$126,990,625	3.977%
Hawaiian Electric	3/10/2004	2,300,000	\$51.86	\$2.0744	\$150,000	\$49.720	\$4,921,120	\$119,278,000	\$114,356,880	4.126%
IDACORP, Inc.	12/9/2004	4,025,000	\$30.00	\$1.2000	\$300,000	\$28.725	\$5,130,000	\$120,750,000	\$115,620,000	4.248%
Pinnacle West Capital	4/8/2010	6,900,000	\$38.00	\$1.3300	\$190,000	\$36.642	\$9,367,000	\$262,200,000	\$252,833,000	3.572%
Pinnacle West Capital	4/27/2005	6,095,000	\$42.00	\$1.3650	\$250,000	\$40.594	\$8,569,675	\$255,990,000	\$247,420,325	3.348%
Portland General	3/5/2009	12,477,500	\$14.10	\$0.4935	\$375,000	\$13.576	\$6,532,646	\$175,932,750	\$169,400,104	3.713%
Portland General	6/13/2007	23,658,106	\$26.00	\$0.7800	\$700,000	\$25.190	\$19,153,323	\$615,110,756	\$595,957,433	3.114%
Southern Co.	12/6/2000	28,750,000	\$28.50	\$0.9200	\$490,000	\$27.563	\$26,940,000	\$819,375,000	\$792,435,000	3.288%
Westar Energy	11/4/2010	8,625,000	\$25.54	\$0.8939	\$250,000	\$24.617	\$7,959,888	\$220,282,500	\$212,322,613	3.613%
Westar Energy	5/29/2008	6,900,000	\$24.28	\$0.8498	\$325,000	\$23.383	\$6,188,620	\$167,532,000	\$161,343,380	3.694%
Weighted Average Flotation Costs							\$236,151,446	\$7,047,904,631	\$6,811,753,185	3.351%
							FLOTATION COSTS			3.35%

The flotation adjustment is derived by dividing the dividend yield by 1-F (where F = flotation costs expressed in percentage terms), or by 0.9665, and adding that result to the constant growth rate to determine the cost of equity. Using the formulas shown previously in my testimony, the Constant Growth DCF calculation is modified as follows to accommodate an adjustment for flotation costs:

$$k = \frac{D \times (1 + .5g)}{P \times (1 - F)} + g$$

FLOTATION COST ADJUSTMENT

Flotation Cost Adjustment - Proxy Group

		[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]
		Annualized Dividend	Stock Price	Dividend Yield	Expected Dividend Yield	Expected Div. Yield Adj. for Flotation Costs	Zacks EPS Growth	Value Line EPS Growth	First Call	Average Growth Estimate	DCF k(e)	Flotation Adjusted DCF k(e)
American Electric Power	AEP	\$1.84	\$37.12	4.96%	5.05%	5.22%	4.00%	3.50%	3.71%	3.74%	8.79%	8.96%
Cleco Corp.	CNL	\$1.12	\$34.84	3.21%	3.31%	3.43%	7.00%	8.00%	3.00%	6.00%	9.31%	9.43%
Empire District Electric	EDE	\$1.28	\$22.12	5.79%	5.97%	6.18%	NA	7.00%	6.00%	6.50%	12.47%	12.68%
Great Plains Energy Inc.	GXP	\$0.83	\$20.64	4.02%	4.17%	4.32%	9.00%	6.00%	7.50%	7.50%	11.67%	11.82%
Hawaiian Electric	HE	\$1.24	\$25.33	4.90%	5.12%	5.30%	8.90%	11.00%	7.90%	9.27%	14.39%	14.57%
IDACORP, Inc.	IDA	\$1.20	\$39.01	3.08%	3.14%	3.25%	4.70%	4.00%	4.67%	4.46%	7.60%	7.71%
Pinnacle West Capital	PNW	\$2.10	\$44.24	4.75%	4.89%	5.06%	5.00%	6.00%	6.98%	5.99%	10.88%	11.05%
Portland General	POR	\$1.06	\$25.10	4.22%	4.34%	4.49%	5.00%	7.50%	4.38%	5.63%	9.97%	10.12%
Southern Co.	SO	\$1.89	\$39.57	4.78%	4.91%	5.08%	5.00%	6.00%	5.51%	5.50%	10.41%	10.58%
Westar Energy	WR	\$1.28	\$27.08	4.73%	4.89%	5.06%	5.50%	8.50%	6.28%	6.76%	11.65%	11.82%
MEAN											10.71%	10.87%
MEAN PROXY GROUP											10.71%	10.87%
DIFFERENCE (FLOTATION COST ADJUSTMENT)												0.16% [12]

Notes:

[1] Source: Bloomberg

[2] Source: Bloomberg, 30 day average price

[3] = column [1] / column [2]

[4] = column [3] x (1+ .5 x column [8])

[5] = column [4] / [1- Flotation Cost Percentage]

[6] Source: Zacks

[7] Source: Value Line

[8] Source: First Call

[9] Average of columns [6], [7] and [8]

[10] = column [4] + column [9]

[11] = column [5] + column [9]

[12] Equals mean Adjusted DCF, column [11] - mean Unadjusted DCF, column [10]

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Revenue Adjustment Mechanisms in Effect at Utility Subsidiaries of the Proxy Group

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American Electric Power (AEP)

AEP Texas Central Company	
Rider NDC- Nuclear Decommissioning Collections	The Nuclear Decommissioning Charges collected under this rider are transferred to a trust that will hold the funds for future nuclear plant decommissioning.
Schedule TCRF- Transmission Cost Recovery Factor	Each retail customer connected to the Company's transmission or distribution system will be assessed a non-by-passable transmission service charge adjustment pursuant to this rider.
Rider EECRF- Energy Efficiency Cost Recovery Factors	This Rider recovers the cost of energy efficiency programs not already included in base distribution service rates and is applicable to the kWh sales of retail customers taking retail electric delivery service from the Company.
Rider TCE- True-Up Case Expenses Surcharge	Rider TCE is designed to recover Commission approved true-up case related expenses. This schedule is applicable to energy consumption and demands of retail customers taking transmission and/or distribution service from the Company.
Rider RCS-2 – Rate Case Surcharge #2	Rider RCS-2 is designed to recover Commission approved deferred rate case expenses.
Rider AMSCRF- Advanced Metering System Cost Recovery Fee	This Rider is applicable to retail customers receiving metered service for which the Company will install an advanced metering system during the recovery period approved by the PUCT.
AEP Texas North Company	
Schedule TCRF- Transmission Cost Recovery Factor- ERCOT System	Each retail customer connected to the Company's transmission or distribution system will be assessed a non-by-passable transmission service charge adjustment.
Rider RCS– Rate Case Surcharge	Rider RCS is designed to recover Commission approved rate case expenses.
Rider AMSCRF- Advanced Metering System Cost Recovery Fee	This Rider is applicable to retail customers receiving metered service for which the Company will install an Advanced Metering Infrastructure system during the recovery period approved by the PUCT.
Rider EECRF- Energy Efficiency Cost Recovery Factors	This Rider recovers the cost of energy efficiency programs not already included in base distribution service rates and is applicable to the kWh sales of retail customers taking retail electric delivery service from the Company.
Kingsport Power Company	
Purchased Power Adjustment Rider	Kingsport Power is authorized under this rider to apply a surcharge to all customer bills to allow for changes in the non-fuel cost of purchased power from the Company's wholesale power supplier.

Appalachian Power Company- Virginia	
Environmental and Reliability Cost Recovery Surcharge	Under this rider, the Company will collect an incremental environmental compliance and Transmission and Distribution system reliability cost recovery surcharge.
Fuel Factor Rider	This rider allows the Company to recover its cost of fuel used in generation of electricity.
Transmission Rate Adjustment Clause Rider	The Transmission Rate Adjustment Rider will be applied to all standard customer bills rendered under the applicable standard schedules or special contracts. This Rider allows the Company to recover transmission related investment.
Wheeling Power Company	
Schedule L.E.- Line Extensions	Customers are charged for line extensions based on installed extensions on a monthly basis.
Southwestern Electric Power Company- Arkansas Jurisdiction	
Energy Cost Recovery Rider (ECR)	The Energy Cost Rate recovers the Company's net fuel and purchased energy cost.
Charges for Special or Additional Facilities	In the event facilities in excess of a normal installation are found to be required to serve the Customer's load, or are requested by the Customer and approved by the Company, the Company is required to furnish, install, and maintain such facilities with a monthly charge to the Customer.
Redundant Service Policy for Municipal Accounts	Certain customers are charged additional fees for redundant service. Additional charges are based on consumption.
Extension of Facilities Agreement	This Rider provides for cost recovery of Company investment in the extension of facilities when the revenue generated from such investment will not cover the entire cost.
Radio Frequency Meter Installation Rider	A customer may request (or elect upon request by the Company) to have a radio frequency meter installed under the terms of this Rider as a mutually agreeable solution to Company personnel's lack of meter reading access to Company metering equipment on a customer's premises, due to a locked gate, animal concern, safety concern or other reason. This Rider lays out the one-time, non-refundable installation fee from the customer to the Company.
Energy Efficiency Cost Rate Rider (EECR)	The purpose of this Rider is to establish the EECR rate(s) by which the Company will recover the incremental costs of energy efficiency programs approved by the Commission.
Federal Litigation Consulting Fee Rider	The Federal Litigation Consulting Fee Rate enables the Company to recover the fees and expenses paid by the Company to contract attorneys and consultants retained by the Arkansas Public Service Commission, as authorized by the General Assembly, when it participates in litigation before a federal agency or federal court in proceedings that affect the Company.

Alternative Generation Recovery Rider	This Generation Recovery Rider is designed to adjust monthly billings to recover costs associated with the Stall Generating Facility. The Rider is designed to recover return on and of the generation facility and operation and maintenance expenditures after the facility commences commercial operation.
Southwestern Electric Power Company- Louisiana Jurisdiction	
Off-Peak Service Rider to the Lighting and Power Service Schedule and Metal Melting Service Schedule	This rider is available to customers receiving electric service under either the Lighting and Power Service or the Metal Melting Service schedule when prearrangement has been made by contract for the installation of adequate facilities, including appropriate metering. Customers who contract for service under this rider will be billed a Customer Charge of \$70.00 per month to help defray the additional costs incurred by the Company in providing service hereunder.
Fuel Adjustment Rider	All kilowatt-hours sold will be adjusted to reflect the current cost of fuel. This Rider recovers the net cost of fuel consumed in the Company's generating plants, plus the net cost of purchased economy and emergency energy, as well as energy purchased from qualifying small production or cogeneration facilities.
Charges for Special or Additional Facilities	In the event facilities in excess of a normal installation are found to be required to serve the Customer's load, or are requested by the Customer and approved by the Company, the Company is required to furnish, install, and maintain such facilities with a monthly charge to the Customer.
Rider for Radio Frequency Meter Installation	A customer may request (or elect upon request by the Company) to have a radio frequency meter installed under the terms of this Rider as a mutually agreeable solution to Company personnel's lack of meter reading access to Company metering equipment on a customer's premises, due to a locked gate, animal concern, safety concern or other reason. This Rider lays out the one-time, non-refundable installation fee from the customer to the Company.
Formula Rate Plan Rider Schedule (FRP)	The Formula Rate Plan Rider defines the procedure by which the rates contained in the Company rate schedules may be periodically adjusted. The FRP stipulates an authorized rate of return with a bandwidth.
Southwestern Electric Power Company- East Texas Jurisdiction	
Fixed Fuel Factor Tariff	The Fixed Fuel Factor provides for the recovery of the net costs of fuel used to procure electricity for retail customers.
Energy Efficiency Cost Recovery Rider	This Rider recovers the cost of energy efficiency programs not included in base rates.
Purchased Power and Conservation Factor (PPCF)	This rider covers the costs of demand-side management resources and renewable energy resources that are approved for PPCF cost recovery by the Commission but are not recovered in base rates.
Southwestern Electric Power Company- North Texas Jurisdiction	
Fixed Fuel Factor Rider	This Rider allows for the recovery of the fixed costs related to fuel procurement for power production.

Fuel Surcharge	This surcharge allows for the recovery of the net cost of fuel to the Company to provide retail electric distribution service.
Energy Efficiency Cost Recovery Rider	This Rider recovers the cost of energy efficiency programs not included in base rates.
Columbus Southern Power Company	
Provider of Last Resort Charge Rider	This Rider allows the Company to recoup the costs related to the obligation to customers to be the provider of last resort.
Monongahela Power Litigation Termination Rider	This temporary Rider shall remain in effect until the amounts authorized by the Commission in Case No. 05-765-EL-UNC have been collected.
Transmission Cost Recovery Rider	This Rider allows the Company to recover the costs associated with transmission investment that are not recovered in base rates.
Fuel Adjustment Clause Rider	The Fuel Adjustment Clause Rider permits the Company to pass along to customers the net actual cost of fuel used in power procurement.
Energy Efficiency and Peak Demand Reduction Cost Recovery Rider	The Energy Efficiency and Peak Demand Reduction Cost Recovery charge provides for the recovery of costs related to energy efficiency programs and demand side management programs used to attenuate peak demand.
Enhanced Service Reliability Rider	The Enhanced Service Reliability Riders allows for the recovery of costs associated with improvements made to the reliability and integrity of the distribution system.
gridSMART Rider	This Rider recovers the cost of purchasing and installing SMART technology.
Economic Cost Recovery Rider	Recovery of economic development costs authorized by the Commission.
Ohio Power Company	
Provider of Last Resort Charge Rider	This Rider allows the Company to recoup the costs related to the obligation to customers to be the provider of last resort.
Transmission Cost Recovery Rider	This Rider allows the Company to recover the costs associated with transmission investment that are not recovered in base rates.
Fuel Adjustment Clause Rider	The Fuel Adjustment Clause Rider permits the Company to pass along to customers the net actual cost of fuel used in power procurement.
Energy Efficiency and Peak Demand Reduction Cost Recovery Rider	The Energy Efficiency and Peak Demand Reduction Cost Recovery Rider provides for the recovery of costs related to energy efficiency programs and demand side management programs used to reduce peak demand.

Enhanced Service Reliability Rider	The Enhanced Service Reliability Rider allows for the recovery of costs associated with improvements made to the reliability and integrity of the distribution system.
Economic Cost Recovery Rider	Recovery of economic development costs authorized by the Commission.
Indiana Michigan Power Company- Indiana Jurisdiction	
Fuel Adjustment Rider	The Fuel Adjustment Clause Rider permits the Company to pass along to customers the net actual cost of fuel used in power procurement. The costs eligible for recovery include the average cost of fossil and nuclear fuel consumed at the Company's own plants, plus net purchased power costs, and nuclear fuel disposal costs.
Demand-Side Management/ Energy Efficiency Program Cost Rider	This Rider allows for cost recovery associated with demand-side management and energy efficiency programs.
PJM Cost Rider	This adjustment allows for the recovery of demand-related and energy-related costs related to PJM.
Environmental Compliance Cost Rider	This Rider allows for the recovery of environmental compliance costs not included in base rates.
Clean Coal Technology Rider	The Clean Coal Technology Rider (CTTR) provides for the cost recovery of the revenue requirement associated with CCTR investment, depreciation expense on in-service CCTR property, operation and maintenance expenses on CCTR property, and costs of consumables and chemical agents.
Off-System Sales Margin Sharing Rider	This rider provides for the sharing of off-system sales margins through a per kWh adjustment to applicable customer bills. The adjustment for each tariff class is based upon a specified cost sharing factor calculation.
Indiana Michigan Power Company – Michigan Jurisdiction	
OAD- Nuclear Decommissioning Surcharge Rider	The Nuclear Decommissioning Surcharge Rider provides for cost recovery of future nuclear decommissioning costs. The charge is a per kWh charge by rate class.
OAD- Energy Optimization Surcharge Rider	The Energy Optimization surcharge funds energy optimization programs conducted by a Commission-approved energy optimization program administrator.
Power Supply Cost Recovery	This clause permits the monthly adjustment of rates to recover the booked costs, including transportation costs, reclamation costs, and disposal and reprocessing costs, of fuel burned for electric generation, the booked costs of purchased and net interchange power transactions and the cost of transmission service incurred under reasonable and prudent policies and practices.

Net Lost Revenue Recovery Surcharge	The Commission approved settlement of Case No. U-16180 authorized the creation of a regulatory asset for the Net Lost Revenue associated with lost sales that are caused by the Company's energy optimization program. The lost revenue is to be recovered through this rider.
Kentucky Power Company	
Fuel Adjustment Clause	The Fuel Adjustment clause allows for the recovery of fossil fuel and nuclear fuel consumed in the utility's own plants and the net costs of purchased power. This periodic adjustment allows for the recovery of the difference between actual fuel costs and sales.
Demand-Side Management Adjustment Clause	The Demand-Side Management Clause allows for the recovery of demand-side management programs, net lost revenues, incentives, and any over/under recovery balances.
Environmental Surcharge	The environmental surcharge provides for monthly adjustments based on the difference between the environmental compliance costs in a base period and the current period.
Capacity Charge	Kentucky Power Company is to recover from retail ratepayers the supplemental annual payments tied to the 18-year extension of the Rockpower Unit Power Agreement. The Company will apply surcharges under this Rider designed to enable the recovery from each tariff class of customers.
Public Service Company of Oklahoma	
Fuel Cost Adjustment Rider	The Fuel Cost Adjustment Rider allows for the recovery of the cost of fuel used in generation of electric services plus net purchased power costs.
Regulatory Assessment Rider	This Rider allows for the recovery of an annual assessment as billed by the Commission, and applies to all retail monthly customer billings.
Reliability Vegetation/Undergrounding Rider	The RVU Factor is determined on a quarterly basis for each major rate class to incorporate the previous quarter's Eligible Reliability Costs expended and adjusted by any over or under recovery of costs from the previous three month billing period and applied to the billings for the next quarter. This rider allows for the recovery of reliability costs associated with vegetation management not included in base rates.
Purchased Power Capacity Rider	The Purchased Power Capacity Adjustment Rider allows for recovery of purchased power capacity costs.
Demand-Side Management Cost Recovery Rider	The DSM Rider is designed to recover costs associated with Energy Efficiency and Demand-side Management programs.
Regulatory Asset Recovery Rider	The RAR Rider is designed to recover costs associated with extraordinary operation and maintenance expenses resulting from the January and December 2007 ice storms.
Long-Term Base Load Purchased Power Rider	The BLPP Rider is designed to recover all costs associated with a particular contract, and with recovery of the one-time RFP costs.

Cleco Corporation (CNL)

Cleco Power	
Fuel Cost Adjustment	Monthly adjustment to recover the actual cost of fuel, including the cost of fuel to the company's generation and the cost of purchased power. Any sales of power are credited through this mechanism.
Storm Recovery Charge Adjustment	This adjustment recovers applicable storm restoration costs approved by the Louisiana Public Service Commission. This adjustment is reconciled semi-annually.
Formula Rate Plan	The Formula Rate Plan has a target ROE and capital structure. The FRP also allows for recovery of future revenue requirements for approved capacity purchases, construction, etc. The Company can propose additional projects to the LPSC during the FRP's initial four-year term.
Environmental Cost Adjustment	This adjustment provides for the recovery of certain costs of environmental compliance as an adder to customers' bills. The costs eligible for recovery are prudently incurred air emissions credits associated with complying with federal, state, and local air emission regulations and variable emission mitigation costs.

Empire District (EDE)

Arkansas	
Energy Cost Recovery Rider (ECR)	The annual determination of the ECR recovers EDE's net fuel and purchased energy cost.
Energy Efficiency Cost Recovery Tariff	Establishes rate in which EDE recovers incremental costs of energy efficiency programs. Limited to the incremental costs which represent direct program costs.
Transmission Cost Recovery Rider (TCR)	The TCR recovers EDE's net transmission costs, which will be determined annually.
Kansas	
Energy Cost Adjustment Rider	Monthly fuel cost true-up. Includes fuel costs, purchased energy costs, off-system sales cost/credits and emissions costs. Also includes prior period recovery.
Missouri	
Fuel Adjustment Clause	Semi-annual fuel cost true-up. Includes fuel costs, purchased energy costs, off-system sales cost/credits and emissions costs. Will also include prior recovery period sales variation and interest.
Vegetation Management and Infrastructure Inspection Tracker	Through this mechanism, the costs associated with these activities that vary from a base level are to be deferred for future recovery/refund.
Oklahoma	
DSM Cost Recovery Rider (DSM)	Establishes a DSM rate to receive the incremental costs which represent the direct program costs, associated lost revenues, true-up amounts, and earned program incentives. Annual re-determination.
Fuel Adjustment Rider	A rate to compensate for charges in the cost of fuel burned at the Company's thermal generating plants.
Storm Recovery Rider	True-up of total storm costs.

Great Plains Energy, Inc. (GXP)

KCP&L (Kansas)	
Energy Cost Adjustment (ECA)	Volumetric rate that recovers generation costs including fuel, purchased power, emission allowances, transmission costs. Rate is established monthly
Energy Efficiency Rider	Recovers the costs associated with Commission-approved affordability, energy efficiency and demand response programs. Rider and the cost estimates are filed annually with the Commission.
KCP&L (Missouri)	
None Found	
KCP&L Greater Missouri Operations (Missouri)	
Fuel Adjustment Clause	Through this mechanism, the Company recovers 95% of "prudently incurred" fuel and purchased power costs, net emissions allowance costs, and OSS revenues that vary from the levels included in base rates. The mechanism is adjusted semi-annually.

Hawaiian Electric Industries, Inc. (HE)

Hawaiian Electric (HECO), Hawaii Electric Light (HELCO) and Maui Electric (ME)	
Energy Cost Adjustment Clause	The Hawaii Public Utility Commission (PUC) has allowed rate recovery for the purchased energy costs related to HECO's as-available energy PPAs and for the firm capacity and purchased energy costs related to major PPAs. In addition, electric rates (and consequently the revenues of the electric utility subsidiaries generally) are adjusted for changes in the weighted average price paid for fuel oil and certain components of purchased power, as well as the relative amounts of company-generated power and purchased power.
Revenue Decoupling	Utilities in Hawaii have committed to aggressive clean energy goals, and have gained some certainty in cost recovery through the Hawaii PUC's initial approval of revenue decoupling. Under the new decoupling regime, the PUC will approve a revenue level for HECO based on services authorized. Rates will be adjusted based on sales levels, allowing the utility to continue recovering the cost of providing services, but not to earn additional profit from higher sales. Rate increase or decrease between formal rate cases will occur largely based on independent cost indices. Adjustments will enable recovery of PUC-approved capital additions. (Implemented for HECO)
Integrated Resource Planning Cost Recovery Adjustment	The electric utilities are permitted to recover all reasonably incurred planning and implementation costs associated with the filing of mandatory integrated resource plans every three years.
Demand-Side Management (DSM) Adjustment Clauses	Adjustments are made to Residential, Commercial, and Industrial customer bills in order to recover the respective costs associated with the electric utilities' DSM programs for each customer class.
Purchased Power Adjustment Clause	Adjustments are made to various rate schedules in order to recover purchased power expenses that are not recovered in base rates or through the Energy Cost Adjustment Clause.

IDACORP, Inc. (IDA)

Idaho Power (Idaho)	
Power Cost Adjustment	The Power Cost Adjustment is a monthly adjustment mechanism allowing the Company to recover 95% of the difference between projected power costs and normal power costs included in base rates. In poor water, high cost years, Idaho ratepayers pay 95% of Idaho Power Company's abnormal power supply costs. In good water, low cost years, Idaho ratepayers are credited with 95% of any below normal cost savings.
Energy Efficiency Rider	The Energy Efficiency Rider is a means for Idaho Power to fund most of its demand-side management or energy efficiency, programs. The costs recovered under this rider are subject to prudence review by the Idaho Commission.
Fixed Cost Adjustment (FCA) - Decoupling	The Company establishes the costs charged to customers based on a fixed cost per customer that is then allocated on based on units of consumption. The Fixed Cost Adjustment is the difference between the allowed fixed cost recovery and the actual fixed cost recovery, adjusted for normal weather. The FCA is calculated monthly.
Accelerated Depreciation of metering infrastructure	On May 29, 2009, the Idaho Public Utility Commission allowed IPC to begin three-year accelerated depreciation of the existing metering equipment on June 1, 2009. The order reflects annualized depreciation expense relating to Advanced Metering Infrastructure.
Idaho Power (Oregon)	
Power Cost Adjustment Mechanism (PCAM)	This mechanism is an annual adjustment allowing the Company to recover 90% of the difference between actual power costs and normal power costs included in base rates. The PCA is subject to an earnings test with a deadband of 100 basis points. If the company earns less than its ROE by 100 basis points or more, the PCA true up is a charge to customers. If the Company has earned in excess of 100 basis points more than its allowed ROE, the company is required to include the PCA in a true-up balancing account as a credit to customers (back to a threshold of the authorized ROE plus 100 basis points).
Annual Power Cost Update (APCU)	The APCU allows Idaho Power to reestablish its Oregon base net power supply costs annually, separate from a general rate case, and to forecast net power supply costs for the upcoming water year.
Depreciation Adjustment Rider	This rider recovers accelerated depreciation of the existing metering infrastructure that is replaced by AMI metering, less the revenue requirement impact of the revised depreciation rates.
Energy Efficiency Rider	The Energy Efficiency Rider is a means for the company to recover the analysis and implementation of energy conservation and demand response programs.

Pinnacle West Capital (PNW)

Arizona Public Service	
Renewable Energy Standard (RES)	The RES is a component of the Environmental Benefits Surcharge that collects costs associated with compliance to state renewable energy standards. Related charges and caps may be modified periodically.
Environmental Improvement Surcharge	This surcharge recovers costs associated with investment and expenses for environmental improvements at Company generation facilities that the ACC has approved for recovery. Improvements must have been implemented on or after January 1, 2004, and include ongoing environmental improvement projects and environmental improvement projects comply with prospective required environmental standards.
Competition Rules Compliance Charge (CRCC)	This charge recovers over five years the costs of complying with the ACC Electric Competition Rules that were deferred through December 31, 2004. The CRCC will be canceled once the amount allowed is recovered or five years after the implementation of this rate schedule, whichever occurs first.
Demand Side Management Adjustment Charge	This charge is a component of the Environmental Benefits Surcharge that recovers costs related to Commission approved demand side management programs above those costs included in base rates. The Charge is collected on a monthly basis.
Power Supply Adjustment (PSA)	The PSA applies to most retail electric rate schedules in accordance with their terms. It recovers costs associated with fuel and purchased power.
Transmission Cost Adjustment	This adjustment applies to most retail electric rate schedules in accordance with their terms.

Portland General (POR)

Portland General	
Regulatory Adjustments	This mechanism reflects the effects of regulatory adjustments such as net gains from nonrecurring property transactions, and costs associated with implementation of SB 1149 as well as miscellaneous nonrecurring items.
Public Purpose Charge	The charge is designed to collect funds associated with activities mandated for the benefit of the general public, such as energy conservation, new market transformation, new renewable energy resources and new low-income weatherization.
Energy Efficiency Customer Service	This adjustment is designed to fund Company activities associated with enabling customers to achieve energy efficiency, including but not limited to project facilitation, technical assistance, education and assistance to support programs administered by the Energy Trust of Oregon.
Energy Efficiency Funding Adjustment	This adjustment is designed to fund the acquisition of additional Energy Efficiency Measures for the benefit of the Company's customers, pursuant to the Oregon Renewable Energy Act, through programs administered by the Energy Trust of Oregon.
Renewable Resources Adjustment Clause	This schedule recovers the revenue requirements of qualifying Company-owned or contracted new renewable energy resource projects (including associated transmission) not otherwise included in rates. Additional new renewable projects may be incorporated into this schedule as they are placed in service.
Sales Normalization Adjustment (SNA) - Decoupling	This adjustment establishes balancing accounts and rate adjustment mechanisms to track and mitigate a portion of the transmission, distribution and fixed generation revenue variations caused by variations in applicable Customer Energy usage. The SNA reconciles on a monthly basis, differences between a) The monthly revenues resulting from applying distribution, transmission and fixed generation charges (Fixed Charge Energy Rate) to weather-normalized kWh Energy sales, and b) The Fixed Charge Revenues that would be collected by applying the Monthly Fixed Charge per Customer and to the numbers of active Customers, respectively, for each month.
Annual Power Cost Update	Rates are adjusted annually to account for changes in the Company's projected Net Variable Power Costs. The rate adjustment will be based on the Adjusted NVPC less the NVPC revenues that would occur at the NVPC prices determined in the Company's most recent general rate case applied to forecast loads used to determine changes in Net Variable Power Costs.
Annual Power Cost Variance Mechanism	This mechanism recognizes in rates part of the difference between actual and forecasted Net Variable Power Costs for a given year.

Demand Response Cost Recovery Mechanism	This mechanism will recover expenses associated with the implementation and operation (on a pilot basis) of an automated demand response program not otherwise included in rates. Rate adjustments will commence on January 1, 2012.
Short-Term Transition Adjustment	This schedule calculates the Short-Term Transition Adjustment to reflect the results of an ongoing valuation.
Long-Term Transition Cost Adjustment	This schedule calculates the Long-Term Transition Adjustment.
Underground Conversion Cost Recovery	This recovers costs incurred by the Company to convert electric facilities from overhead to underground from customers within the boundaries of the local government requiring such conversion at the Company's expense.

Southern Company (SO)

Alabama Power Company	
Fuel Cost Recovery	Alabama Power has established fuel cost recovery rates under an energy cost recovery clause ("Rate ECR", see below) approved by the Alabama PSC. Rates are based on an estimate of future energy costs and the current over- or under-recovered balance.
Rate Adjustment for Certificated New Plant (Rate CNP)	Rate CNP is designed to recover costs associated with: • A generating facility that has been granted a certificate of convenience and necessity by the Alabama Public Service Commission (AL PSC), • A power purchase arrangement that has been granted a certificate of convenience and necessity by the AL PSC, or • Compliance with environmental laws, regulations, or other such mandates.
Energy Cost Recovery (ECR) Rate	Rate ECR provides the Company with a means to recover defined energy costs. It also establishes a procedure for the recovery of defined energy costs through base rates.
Differential Factors Rate Rider	The Differential Factors Rate Rider captures the effects of energy losses along the service chain, as well as the effect of seasonal differentials associated with costs recovered under ECR (above).
Natural Disaster Reserve Rate Rider (NDR)	Rate Rider NDR is designed to adjust monthly billings to address the financial impact of operating and maintenance (O&M) expenses attributable to certain natural disasters.
Rate Stabilization and Equalization Factor (RSE)	The Rate RSE lessens the impact, frequency and size of retail rate increase requests by permitting the Company to adjust its charges more readily to achieve the rate of return authorized by the AL Public Service Commission. Charges are increased if projections for the upcoming year show that the designated rate of return range will not be met, and are decreased if projections show that the designated rate of return range will be exceeded.
Georgia Power Company	
Fuel Cost Recovery Rider	Georgia Power Company has established fuel cost recovery rates that are approved by the Georgia PSC. Fuel cost recovery revenues as recorded on the financial statements are adjusted for differences in actual recoverable costs and amounts billed in current regulated rates.
Environmental Compliance Cost Recovery Rider	Georgia Power's Environmental Compliance costs are recovered in base rates.
Demand Side Management Residential (DSM-R) Rider	The DSM-R rider will collect the projected program costs and additional sum amount for certificated Residential Demand Side Management (DSM) programs.
Demand Side Management Commercial (DSM-C) Rider	The DSM-C rider will collect the projected program costs and additional sum amount for approved and certified Commercial Demand Side Management (DSM) programs.

Nuclear Development Capital Cost Recovery	The Georgia Nuclear Financing Act and the Georgia PSC certification of Plant Vogtle Units 3 and 4 allows Georgia Power to recover financing costs for construction of the new nuclear units during the construction period beginning in 2011.
Alternative Rate Plan	On December 21, 2010, the Georgia PSC approved the 2010 ARP. Under the terms of the 2010 ARP, Georgia Power will amortize approximately \$92 million of its remaining regulatory liability related to other cost of removal obligations over the three years ending December 31, 2013. Also under the terms of the 2010 ARP, effective January 1, 2011, Georgia Power increased its (1) traditional base tariff rates by approximately \$347 million; (2) Demand-Side Management (DSM) tariff rates by approximately \$31 million; (3) ECCR tariff rate by approximately \$168 million; and (4) Municipal Franchise Fee (MFF) tariff rate by approximately \$16 million, for a total increase in base revenues of approximately \$562 million. Additional base rate adjustments will be made to Georgia Power's tariffs in 2012 and 2013. Under the 2010 ARP, Georgia Power's retail ROE is set at 11.15% and earnings will be evaluated against a retail ROE range of 10.25% to 12.25%. Two-thirds of any earnings above 12.25% will be directly refunded to customers, with the remaining one-third retained by Georgia Power. If at any time during the term of the 2010 ARP, Georgia Power projects that retail earnings will be below 10.25% for any calendar year, it may petition the Georgia PSC for the implementation of an Interim Cost Recovery (ICR) tariff to adjust Georgia Power's earnings back to a 10.25% retail ROE. In lieu of requesting implementation of an ICR tariff, or if the Georgia PSC chooses not to implement the ICR, Georgia Power may file a full rate case.
Gulf Power Company	
Cost Recovery Clause – Fossil Fuel and Purchased Power	Gulf Power files a rate clause request annually with the Florida Public Service Commission (FPSC) to recover costs associated with changing efficiency, cost of fossil fuel, and cost of purchased power. Revenues are adjusted for differences between recoverable costs and amounts actually recovered in current rates.
Purchased Power Capacity Cost Recovery Clause	Recovery of payments made by the Company for capacity, net of revenues received by the Company for capacity sales.
Energy Conservation Cost Recovery	Gulf Power files a rate clause request annually with the FPSC to recover costs associated with energy conservation. Revenues are adjusted for differences between recoverable costs and amounts actually recovered in rates.
Environmental Cost Recovery Clause	The Florida Legislature has adopted legislation for an environmental cost recovery clause, which allows an electric utility to petition the FPSC for recovery of prudent environmental compliance costs that are not being recovered through base rates or any other recovery mechanism. Gulf Power files a rate clause request annually with the FPSC to recover costs associated with environmental compliance. Revenues are adjusted for differences between recoverable costs and amounts actually recovered in current rates.

Mississippi Power Company	
Fuel Cost Recovery Clause	Mississippi Power's fuel cost recovery provisions are adjusted annually to reflect increases or decreases in such costs. Includes a true-up adjustment for any over/under collection in the twelve month period immediately preceding the calculation month.
Energy Cost Management Clause	Recovers budgeted transaction costs for entering forward or financial contracts such as option premiums for both gas and electricity futures contracts and budgeted gas transportation and electricity transmission necessary to meet futures contract obligations for a twelve month period. Includes a true-up adjustment for any over/under collection in the twelve month period immediately preceding the calculation month.
Performance Evaluation Plan	Annually on or before November 15, a determination will be made as to whether or not the Company's revenues should be increased, decreased, or remain the same. Based on a twelve month ending Projected Retail Return on Investment as well as the Company's Performance Rating and a Range of No Change. No annual revenue adjustment may exceed 4.00%.
Environmental Compliance Overview Plan	Approved environmental compliance costs are recovered through cost recovery provisions. Within limits, these rates are adjusted to reflect increases or decreases in such costs as required.
System Restoration Rider (SRR)	Under a revised SRR calculation method (January 2009), the Mississippi PSC is no longer required to set a cap on a property damage reserve, or to authorize the calculation of an annual property damage accrual.

Westar Energy (WR)

Northern and Southern Region	
Fuel Charge	The fuel charge includes costs incurred in production of electricity, as well as the Off-system Sales Adjustment, which credits profits from wholesale sales to retail customers. Wholesale sales are transactions in which the Company sells energy to other wholesale entities such as neighboring utilities, municipalities and power marketers.
Environmental Cost Recovery Rider	This adjustment is designed to recover annual capital investment-related revenue requirements that are associated with Westar's Environmental Improvements Projects. The ECRC is collected on a monthly basis and includes an annual true-up.
Retail Energy Cost Adjustment	This adjustment recovers costs associated with the fuel costs to produce electricity, purchased power cost, emission allowance costs, and the off-system sales adjustment, which credits profits from wholesale sales to retail customers.
Transmission Delivery Charge	This charge includes costs related to the construction and maintenance of Westar Energy's transmission system.
Storm Costs	The Company accumulated and deferred for future recovery costs related to restoring its electric transmission and distribution systems from damages sustained during unusually damaging storms. The Company amortizes these costs over periods ranging from three to five years and earns a return on a majority of this asset.
Energy Efficiency Program Costs	The Company accumulates and defers for future recovery costs related to its various energy efficiency programs. The Company will amortize such costs over a one-year period. The Company does not earn a return on this asset.

R. B. HEVERT
Direct Exhibit
DC P.S.C. - July, 2011

Introduced as:
PEPCO _____ (D) -9

Summary of Decoupling Mechanisms

Defined Adjustment

No.	State	Utility	Specific Adjustment to ROE	Docket	Date of Final Order	Litigated or Settled
1	DC	Potomac Electric Power Co.	50 basis points	F.C. 1053	9/28/2009	Litigated
2	DC	Potomac Electric Power Co.	50 basis points	F.C. 1076	3/2/2010	Litigated
3	MD	Baltimore Gas & Electric	50 basis points	C-9230	3/9/2011	Litigated
4	MD	Delmarva Power & Light Co.	50 basis points	C-9093	7/19/2007	Litigated
5	MD	Delmarva Power & Light Co.	50 basis points	C-9192	12/30/2009	Litigated
6	MD	PEPCO	50 basis points	C-9092	7/19/2007	Litigated
7	MD	PEPCO	50 basis points	C-9217	8/6/2010	Litigated
8	MT	Northwestern Energy	25 basis points	D2009.9.129, D2007.7.82	12/9/2010	Litigated
9	NY	Central Hudson	10 basis points	08-E-0887	6/22/2009	Litigated
10	OR	Portland General Electric	10 basis points	UE 197	1/22/2009	Settled
11	OR	Portland General Electric	10 basis points	UE 204	1/22/2010	Settled

Non-Defined Adjustment

No.	State	Utility	Specific Adjustment to ROE	Docket	Date of Final Order	Litigated or Settled
12	CT	United Illuminating Company	No [1]	08-07-04	1/20/2009	Litigated
13	HI	Hawaiian Electric	No [1]	2008-0083	12/29/2010	Litigated
14	MA	Massachusetts Electric Co. & Nantucket Electric Co.	No [1]	D.P.U 09-39	11/30/2009	Litigated
15	MA	Western MA Electric	No [1]	DPU 10-70	1/31/2011	Litigated
16	NY	Consolidated Edison	No [2]	07-E-0523	3/25/2008	Litigated
17	NY	Consolidated Edison	No [1]	08-E-0539	4/24/2009	Litigated

No Adjustment

No.	State	Utility	Specific Adjustment to ROE	Docket	Date of Final Order	Litigated or Settled
18	CA	Pacific Gas & Electric	No	CA Code Sec. 9 Section 739(3) and Sec. 10 Section 739.10 as amended by A.B. XI 29; Decisions 98-03-063 & 07-09-043	N/A	N/A
19	CA	San Diego Gas & Electric	No	see above	N/A	N/A
20	CA	Southern California Edison	No	see above	N/A	N/A
21	ID	Idaho Power Company	No	IPC-E-08-10	1/30/2009	Litigated
22	MI	Consumers Energy Co.	No	C-U-15645	11/2/2009	Litigated
23	MI	Consumers Energy Co.	No [3]	C-U-16191	11/4/2010	Litigated
24	MI	Detroit Edison Co.	No	C-U-15768	1/11/2010	Litigated
25	MI	Upper Peninsula Power Co.	No	C-U-15988	12/16/2009	Settled
26	MI	Upper Peninsula Power Co.	No	C-U-16166	12/21/2010	Settled
27	NY	Central Hudson	No	09-E-0588	6/16/2010	Settled
28	NY	Consolidated Edison	No	09-E-0428	3/25/2010	Settled
29	NY	Niagara Mohawk	No	10-E-0050, 08-E-0827	1/24/2011	Litigated
30	NY	NY State Electric & Gas Corp.	No	C-09-E-0715 & C-09-E-0716	9/16/2010	Settled
31	NY	Orange & Rockland Utilities	No	07-E-0949	7/23/2008	Settled
32	NY	Rochester Gas & Electric Corp.	No	C-09-E-0717 & C-09-E-0718	9/16/2010	Settled
33	OR	Portland General Electric	No [4]	UE 215	12/17/2010	Settled
34	WI	Wisconsin Public Service Co	No [5]	6690-UR-119	12/30/2008	Settled
35	WI	Wisconsin Public Service Co	No	6690-UR-120	1/13/2011	Litigated

Source: Regulatory Research Associates

Notes:

[1] The Commission and/or parties stated the ROE was affected by the implementation of a decoupling mechanism but the adjustment was not specified.

[2] No ROE adjustment was made, although a 10 basis point adjustment was discussed but, ultimately, considered offset by other rate measures and revenue adjustments adopted by the Commission.

[3] No ROE adjustment was specified; however, we note the Commission's statement that the discontinuance of all other existing trackers removes much of the justification for lowering the Company's ROE to reflect the decreased business risk under revenue decoupling.

[4] No ROE adjustment was specified; however, the stipulating parties agreed upon an ROE of 10.00% that, it was noted, is equivalent to the Company's current approved ROE. See Line 11.

[5] ROE was not discussed or determined in the order.

Exhibit (D)-10

R. B. HEVERT
Direct Exhibit
DC P.S.C. - July, 2011

Introduced as:
PEPCO _____ (D)-10

Common Equity Ratio

Summary Data

Company Name	Ticker	2011Q1	2010Q4	2010Q3	2010Q2	2010Q1	2009Q4	2009Q3	2009Q2	Overall Average
American Electric Power	AEP	48.61%	50.05%	53.10%	52.55%	52.51%	48.47%	49.05%	48.94%	50.41%
Cleco Power LLC	CNL	46.98%	47.33%	51.14%	50.52%	50.69%	45.45%	47.08%	46.43%	48.20%
Empire District Electric	EDE	51.03%	50.93%	50.99%	50.50%	51.88%	50.80%	48.49%	46.88%	50.19%
Great Plains Energy Inc.	GXP	53.59%	52.23%	52.34%	54.19%	53.82%	53.70%	52.96%	52.39%	53.15%
Hawaiian Electric Company, Inc.	HE	55.86%	55.83%	55.62%	55.42%	55.31%	55.26%	53.41%	56.88%	55.45%
IDACORP, Inc.	IDA	48.84%	46.61%	46.22%	48.20%	47.56%	47.45%	48.15%	46.98%	47.50%
Pinnacle West	PNW	52.57%	52.97%	52.98%	51.49%	49.78%	50.37%	50.74%	48.18%	51.14%
Portland General	POR	47.74%	46.83%	46.73%	46.26%	46.47%	46.94%	49.37%	49.17%	47.44%
Southern Co.	SO	50.59%	49.27%	48.75%	50.45%	50.71%	50.01%	50.38%	48.99%	49.89%
Westar Energy	WR	59.24%	59.37%	59.48%	58.67%	58.41%	58.73%	58.86%	57.04%	58.72%
Proxy Group Average		51.50%	51.14%	51.73%	51.82%	51.71%	50.72%	50.85%	50.19%	51.21%

Underlying Data

		Common Equity Ratio							
Company Name	Ticker	2011Q1	2010Q4	2010Q3	2010Q2	2010Q1	2009Q4	2009Q3	2009Q2
AEP Texas Central Company	AEP	44.99%	44.85%	44.76%	43.79%	43.89%	43.79%	43.67%	46.13%
AEP Texas North Company	AEP	45.88%	45.52%	45.18%	45.09%	45.73%	45.58%	46.63%	46.51%
Alabama Power Company	SO	46.46%	46.54%	47.06%	46.45%	46.16%	45.80%	45.75%	43.43%
Appalachian Power Company	AEP	41.53%	44.21%	43.87%	43.52%	45.05%	44.35%	44.82%	44.58%
Arizona Public Service Company	PNW	52.57%	52.97%	52.98%	51.49%	49.78%	50.37%	50.74%	48.18%
Cleco Power LLC	CNL	46.98%	47.33%	51.14%	50.52%	50.69%	45.45%	47.08%	46.43%
Columbus Southern Power Company	AEP	50.87%	50.81%	48.47%	47.05%	46.48%	46.95%	46.18%	46.81%
Empire District Electric Company	EDE	51.03%	50.93%	50.99%	50.50%	51.88%	50.80%	48.49%	46.88%
Georgia Power Company	SO	51.17%	51.32%	50.22%	50.69%	50.99%	49.77%	51.57%	49.55%
Gulf Power Company	SO	47.52%	46.71%	45.40%	47.46%	48.46%	47.25%	46.75%	46.23%
Hawaiian Electric Company, Inc.	HE	55.86%	55.83%	55.62%	55.42%	55.31%	55.26%	53.41%	56.88%
Idaho Power Co.	IDA	48.84%	46.61%	46.22%	48.20%	47.56%	47.45%	48.15%	46.98%
Indiana Michigan Power Company	AEP	48.86%	48.47%	46.80%	46.29%	46.44%	45.85%	45.74%	45.30%
Kansas City Power & Light Company	GXP	52.66%	52.90%	53.16%	52.29%	51.98%	51.97%	51.93%	51.33%
Kansas Gas and Electric Company	WR	56.52%	57.00%	57.24%	56.49%	56.24%	57.15%	57.23%	56.43%
KCP&L Greater Missouri Operations Company	GXP	54.52%	51.55%	51.52%	56.09%	55.66%	55.43%	53.99%	53.44%
Kentucky Power Company	AEP	45.50%	44.84%	44.21%	43.59%	44.27%	44.04%	44.00%	43.94%
Kingsport Power Company	AEP	59.12%	57.96%	100.00%	100.00%	100.00%	51.61%	55.30%	54.84%
Mississippi Power Company	SO	57.21%	52.51%	52.30%	57.20%	57.23%	57.24%	57.45%	56.74%
Ohio Power Company	AEP	54.52%	53.43%	52.37%	52.33%	49.41%	49.94%	50.14%	53.32%
Portland General Electric Company	POR	47.74%	46.83%	46.73%	46.26%	46.47%	46.94%	49.37%	49.17%
Public Service Company of Oklahoma	AEP	45.21%	46.45%	46.65%	45.41%	45.33%	45.61%	48.55%	47.44%
Southwestern Electric Power Company	AEP	49.58%	49.15%	49.07%	47.81%	47.41%	51.71%	51.52%	48.17%
Westar Energy (KPL)	WR	61.96%	61.74%	61.72%	60.84%	60.58%	60.31%	60.48%	57.65%
Wheeling Power Co	AEP	NA	64.89%	62.73%	63.16%	63.54%	63.72%	62.98%	61.25%

Notes

Source: SNL Financial

Long Term Debt Ratio

Summary Data

Company Name	Ticker	2011Q1	2010Q4	2010Q3	2010Q2	2010Q1	2009Q4	2009Q3	2009Q2	Overall Average
American Electric Power	AEP	51.39%	49.95%	46.90%	47.45%	47.49%	51.53%	50.95%	51.06%	49.59%
Cleco Power LLC	CNL	53.02%	52.67%	48.86%	49.48%	49.31%	54.55%	52.92%	53.57%	51.80%
Empire District Electric	EDE	48.97%	49.07%	49.01%	49.50%	48.12%	49.20%	51.51%	53.12%	49.81%
Great Plains Energy Inc.	GXP	46.41%	47.77%	47.66%	45.81%	46.18%	46.30%	47.04%	47.61%	46.85%
Hawaiian Electric Company, Inc.	HE	44.14%	44.17%	44.38%	44.58%	44.69%	44.74%	46.59%	43.12%	44.55%
IDACORP, Inc.	IDA	51.16%	53.39%	53.78%	51.80%	52.44%	52.55%	51.85%	53.02%	52.50%
Pinnacle West	PNW	47.43%	47.03%	47.02%	48.51%	50.22%	49.63%	49.26%	51.82%	48.86%
Portland General	POR	52.26%	53.17%	53.27%	53.74%	53.53%	53.06%	50.63%	50.83%	52.56%
Southern Co.	SO	49.41%	50.73%	51.25%	49.55%	49.29%	49.99%	49.62%	51.01%	50.11%
Westar Energy	WR	40.76%	40.63%	40.52%	41.33%	41.59%	41.27%	41.14%	42.96%	41.28%
Proxy Group Average		48.50%	48.86%	48.27%	48.18%	48.29%	49.28%	49.15%	49.81%	48.79%

Underlying Data

		Long Term Debt Ratio							
Company Name	Ticker	2011Q1	2010Q4	2010Q3	2010Q2	2010Q1	2009Q4	2009Q3	2009Q2
AEP Texas Central Company	AEP	55.01%	55.15%	55.24%	56.21%	56.11%	56.21%	56.33%	53.87%
AEP Texas North Company	AEP	54.12%	54.48%	54.82%	54.91%	54.27%	54.42%	53.37%	53.49%
Alabama Power Company	SO	53.54%	53.46%	52.94%	53.55%	53.84%	54.20%	54.25%	56.57%
Appalachian Power Company	AEP	58.47%	55.79%	56.13%	56.48%	54.95%	55.65%	55.18%	55.42%
Arizona Public Service Company	PNW	47.43%	47.03%	47.02%	48.51%	50.22%	49.63%	49.26%	51.82%
Cleco Power LLC	CNL	53.02%	52.67%	48.86%	49.48%	49.31%	54.55%	52.92%	53.57%
Columbus Southern Power Company	AEP	49.13%	49.19%	51.53%	52.95%	53.52%	53.05%	53.82%	53.19%
Empire District Electric Company	EDE	48.97%	49.07%	49.01%	49.50%	48.12%	49.20%	51.51%	53.12%
Georgia Power Company	SO	48.83%	48.68%	49.78%	49.31%	49.01%	50.23%	48.43%	50.45%
Gulf Power Company	SO	52.48%	53.29%	54.60%	52.54%	51.54%	52.75%	53.25%	53.77%
Hawaiian Electric Company, Inc.	HE	44.14%	44.17%	44.38%	44.58%	44.69%	44.74%	46.59%	43.12%
Idaho Power Co.	IDA	51.16%	53.39%	53.78%	51.80%	52.44%	52.55%	51.85%	53.02%
Indiana Michigan Power Company	AEP	51.14%	51.53%	53.20%	53.71%	53.56%	54.15%	54.26%	54.70%
Kansas City Power & Light Company	GXP	47.34%	47.10%	46.84%	47.71%	48.02%	48.03%	48.07%	48.67%
Kansas Gas and Electric Company	WR	43.48%	43.00%	42.76%	43.51%	43.76%	42.85%	42.77%	43.57%
KCP&L Greater Missouri Operations Company	GXP	45.48%	48.45%	48.48%	43.91%	44.34%	44.57%	46.01%	46.56%
Kentucky Power Company	AEP	54.50%	55.16%	55.79%	56.41%	55.73%	55.96%	56.00%	56.06%
Kingsport Power Company	AEP	40.88%	42.04%	0.00%	0.00%	0.00%	48.39%	44.70%	45.16%
Mississippi Power Company	SO	42.79%	47.49%	47.70%	42.80%	42.77%	42.76%	42.55%	43.26%
Ohio Power Company	AEP	45.48%	46.57%	47.63%	47.67%	50.59%	50.06%	49.86%	46.68%
Portland General Electric Company	POR	52.26%	53.17%	53.27%	53.74%	53.53%	53.06%	50.63%	50.83%
Public Service Company of Oklahoma	AEP	54.79%	53.55%	53.35%	54.59%	54.67%	54.39%	51.45%	52.56%
Southwestern Electric Power Company	AEP	50.42%	50.85%	50.93%	52.19%	52.59%	48.29%	48.48%	51.83%
Westar Energy (KPL)	WR	38.04%	38.26%	38.28%	39.16%	39.42%	39.69%	39.52%	42.35%
Wheeling Power Co	AEP	NA	35.11%	37.27%	36.84%	36.46%	36.28%	37.02%	38.75%

Notes

Source: SNL Financial

K. M. MCGOWAN
Direct Testimony
DC P.S.C. - July, 2011

Introduced as:
PEPCO _____ (E)

POTOMAC ELECTRIC POWER COMPANY

BEFORE THE
PUBLIC SERVICE COMMISSION OF THE DISTRICT OF COLUMBIA
DIRECT TESTIMONY OF KEVIN M. MCGOWAN
FORMAL CASE NO. _____

1 Q. PLEASE STATE YOUR NAME AND POSITION.

2 A. My name is Kevin M. McGowan. I am Vice President
3 and Treasurer of Pepco Holdings, Inc. (PHI). I am
4 testifying on behalf of Potomac Electric Power Company
5 (Pepco or the Company).

6 Q. WHAT IS YOUR EDUCATIONAL AND PROFESSIONAL EXPERIENCE?

7 A. I graduated from the University of Texas at San
8 Antonio receiving a Bachelor of Business Administration
9 degree in both Accounting and Business Data Systems. I
10 also graduated from the University of Chicago Graduate
11 School of Business and received a Masters of Business
12 Administration in Finance. I am a Certified Public
13 Accountant.

14 I joined the Pepco organization in 1998 as the Vice
15 President and Treasurer of Potomac Capital Investments, a
16 subsidiary of Pepco. In 2004, I transferred to Pepco's
17 Power Delivery group and eventually to PHI, where I have
18 held various financial positions. In March 2009, I
19 became Vice President and Treasurer of PHI. Prior to
20 joining the Pepco organization, I worked for Duty Free

1 International, an international retail company, and prior
2 to that I worked for Ernst & Young.

3 **Q. WHAT ARE YOUR RESPONSIBILITIES IN YOUR ROLE AS VICE**
4 **PRESIDENT AND TREASURER?**

5 A. I am responsible for PHI's corporate finance,
6 treasury, credit, investment and risk management
7 activities. As part of my responsibilities, I am
8 responsible for the Company's fixed income borrowings and
9 capital structure, the credit rating agencies
10 relationship, and I am involved with managing the
11 Company's relationships with the financial community.

12 **Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?**

13 A. The purpose of my testimony is to present and
14 support the Company's request to earn an overall rate of
15 return (ROR) of 8.64% on its distribution rate base in
16 the District of Columbia. Also, I will present the
17 Company's capital structure and current credit ratings,
18 and explain why it is critical to the Company, and
19 beneficial to the customers that Pepco maintains a strong
20 investment grade credit rating. Finally, I will provide
21 a brief overview of the financial modeling assumptions
22 used to determine the impact of regulatory lag on the
23 Company's ability to earn its allowed ROR. This
24 testimony was prepared by me or under my direct

1 supervision and control. The source documents for my
2 testimony are Company records, public documents and my
3 personal knowledge and experience.

4 **Q. WILL YOU PLEASE SUMMARIZE YOUR TESTIMONY?**

5 A. As shown in PEPCO (E)-1, the Company is requesting
6 an overall rate of return of 8.64% on its distribution
7 rate base in the District of Columbia. This overall rate
8 of return is the weighted average, based on the Company's
9 March 31, 2011 capital structure ratios of 49.23% common
10 equity and 50.77% long-term debt, its embedded long-term
11 debt cost of 6.60% and its return on common equity of
12 10.75%, as determined by Company Witness Hevert.

13 **CAPITAL STRUCTURE AND CREDIT RATING**

14 **Q. WHAT FACTORS INFLUENCE THE COMPANY'S CAPITAL STRUCTURE?**

15 A. It is necessary to consider the relative costs and
16 risks of the long-term debt and common equity that
17 comprise the Company's capital structure. In general,
18 contractual interest and principal payments to long-term
19 debt holders have priority over non-contractual dividend
20 payments to common equity holders. As long-term debt
21 presents lower risk to the investor, it nominally offers
22 a lower rate of return to the investor and therefore
23 carries a lower cost to the issuer. Conversely, as
24 common equity presents higher risk to the investor, it

1 nominally offers a higher rate of return to the investor
2 and therefore carries a higher cost to the issuer.

3 Given the trade-offs between the costs and risks of
4 long-term debt and common equity, the Company must
5 primarily consider its financial integrity, as nominally
6 reflected in its credit ratings and other key financial
7 metrics in order to successfully balance the needs of its
8 customers and investors. In general, a higher credit
9 rating allows the Company to access a larger investor
10 base and improve the sources of financing it can access
11 from the capital markets. Conversely, the lower the
12 Company's credit rating, the more difficult and more
13 costly it is for the Company to access the capital
14 markets, which consequently will result in a higher cost
15 to our customers.

16 **Q. WHAT IS THE OVERRIDING FACTOR INFLUENCING FORMATION OF**
17 **THE CAPITAL STRUCTURE?**

18 A. Given the direct link between financial integrity
19 and capital structure, the overriding factor influencing
20 the Company's capital structure is to ensure our credit
21 rating metrics support our credit rating. The Company's
22 capital structure has been critical in achieving a level
23 of financial integrity that allows it to raise the

1 necessary capital to serve our customers' needs in terms
2 of reliable and cost-effective electric service.

3 **Q. WHAT CAPITAL STRUCTURE DOES THE COMPANY RECOMMEND FOR THE**
4 **PURPOSE OF RATEMAKING IN THESE PROCEEDINGS?**

5 A. As indicated in PEPCO (E)-2, the capital structure
6 the Company recommends for these proceedings is:

7 Long-Term Debt 50.77%

8 Common Equity 49.23%

9 This capital structure is consistent with the Company's
10 goals and objectives, and necessary to maintain our
11 current credit ratings. In addition, our current credit
12 ratings are based on our commitment to maintain a capital
13 structure consistent with these percentages. We have
14 also communicated these targets to the financial
15 community.

16 **Q. IS THIS CAPITAL STRUCTURE CONSISTENT WITH INDUSTRY**
17 **PRACTICE AND MEDIANS?**

18 A. Yes. The Company's recommended capital structure is
19 consistent with the 2010 full-year and 2011 year-to-date
20 reported medians of 49.36% and 49.37%, respectively, of
21 the common equity ratios of electric utilities as
22 published in the April 2011 edition of Regulatory
23 Research Associates' "Regulatory Focus: Major Rate Case
24 Decisions", as well as with a 2012 - 2016 forecast range

1 from 49.0% to 49.5% for the average equity ratio of the
2 Electric Utility (East) Industry sector between 2012 and
3 2016, as published by Value Line on May 27, 2011.

4 **Q. ARE THERE OTHER REASONS THIS CAPITAL STRUCTURE IS**
5 **APPROPRIATE FOR USE IN THIS PROCEEDING?**

6 A. Yes. As indicated in the testimony of Company
7 Witness Hevert, the Company's recommended capital
8 structure is reasonable given a mean common equity ratio
9 of 51.21% (range between 47.44% and 58.72%) for the 10
10 companies constituting the Company's peer group for
11 purposes of these proceedings.

12 **Q. WHAT ARE THE COMPANY'S CREDIT RATINGS BY MAJOR RATING**
13 **AGENCIES?**

14 A. Pepco's long-term corporate credit ratings
15 (unsecured debt ratings) are BBB+, Baa2 and A- from S&P,
16 Moody's and Fitch, respectively. As noted in S&P's
17 "Global Credit Portal" report dated January 24, 2011, 68%
18 of U.S. investor-owned electric utilities carry ratings
19 from BBB- to BBB+, with an additional 28% rated A-, or
20 better.

21 While specific financial metrics and how they are
22 weighted may differ among the three rating agencies, the
23 Company's current ratings generally indicate that the

1 Company should have reasonable access to the capital
2 markets and adequate liquidity under most scenarios.

3 **Q. PLEASE BRIEFLY DESCRIBE THE IMPORTANCE OF THE COMPANY'S**
4 **CREDIT RATINGS.**

5 A. As previously stated, the Company's credit ratings
6 indicate the rating agencies' assessment of the Company's
7 ability to meet its obligations to its long-term debt
8 holders. The higher the credit rating, the greater the
9 perceived likelihood that the debt investors will receive
10 their interest and principal payments as expected. As
11 such, a company with a higher credit rating has access to
12 a larger investor base, faces fewer restrictive covenants
13 and can issue long-term debt at lower cost. This is
14 particularly advantageous today given the Company's plans
15 to invest a significant amount of capital over the next
16 five years, especially in system reliability, the
17 Blueprint for the Future and other distribution
18 infrastructure projects. In addition, given the
19 significant credit commitments associated with the
20 Standard Offer Service (SOS) procurement process, a high
21 credit rating allows the Company the option to obtain the
22 best pricing, terms and conditions from the load-serving
23 entities.

1 Conversely, lower credit ratings reflect increased
2 investor risk; therefore, investors expect to be paid
3 more to provide funds to such an issuer. In addition,
4 lower credit ratings typically result in investors
5 demanding more restrictive terms and covenants from the
6 issuer. Lower credit ratings also limit the pool of
7 investors that may otherwise invest in the Company due to
8 ratings restrictions imposed by some institutional
9 investors. These additional costs associated with lower
10 credit ratings will only increase the costs to our
11 customers.

12 **Q. WHAT ARE THE BENEFITS OF INVESTMENT GRADE STATUS FOR THE**
13 **COMPANY'S CUSTOMERS?**

14 A. It is important for customers to be served by a
15 financially strong utility that is able to access capital
16 markets in a cost-effective manner. For example, when
17 liquidity disappeared from short-term credit markets
18 during the onset of the U.S. banking crisis in 2008, the
19 Company had difficulty (and during a period of time was
20 unable) to roll-over short-term debt used to temporarily
21 finance its utility construction and operations
22 activities. As a result, the Company sought and received
23 Commission approval to issue and sell \$250 million of
24 long-term debt securities, which the Company was only

1 able to do on acceptable terms because of its investment-
2 grade credit ratings.

3 **Q. WILL AN INVESTMENT GRADE CREDIT RATING BENEFIT CUSTOMERS**
4 **IN THE FUTURE?**

5 A. Yes, looking forward over the next five years, the
6 Company plans to invest significant capital into critical
7 infrastructure and reliability investments. This capital
8 investment must be financed through the debt and equity
9 markets. A strong investment grade credit rating will
10 allow the Company timely access to capital markets, will
11 result in lower cost financing and will lower the cost of
12 service to our customers. In addition, the Company has
13 significant credit commitments to load-serving entities
14 in the SOS procurement process. A strong investment
15 grade credit rating allows the Company to obtain the best
16 pricing, terms, and conditions.

17 **OVERALL RATE OF RETURN**

18 **Q. HOW DID YOU CALCULATE THE COMPANY'S EMBEDDED COST OF**
19 **LONG-TERM DEBT?**

20 A. The embedded cost of long-term debt was calculated
21 in the same manner used in the Company's previous rate
22 filing (Formal Case No. 1076), as shown in PEPCO (E)-3
23 and PEPCO (E)-4.

1 Q. WHAT OVERALL RATE OF RETURN IS THE COMPANY REQUESTING IN
2 THESE PROCEEDINGS?

3 A. The Company is requesting an overall rate of return
4 of 8.64% on its distribution rate base in the District of
5 Columbia, as provided in PEPCO (E)-1.

6 Q. HAVE YOU PREPARED A FORECAST OF THE 2012 REVENUE
7 REQUIREMENT FOR PEPCO'S DISTRICT OF COLUMBIA
8 JURISDICTION?

9 A. Yes. A forecast of the 2012 revenue requirement for
10 Pepco's District of Columbia jurisdiction was prepared
11 for this case to demonstrate the effects of regulatory
12 lag. That forecast appears in PEPCO F-(8) page 2
13 accompanying the testimony of Company Witness Hook.

14 Q. HOW WAS THE FORECAST OF THE 2012 REVENUE REQUIREMENT FOR
15 PEPCO'S DISTRICT OF COLUMBIA JURISDICTION PREPARED?

16 A. It was prepared based on projections of Pepco's 2012
17 operating results and growth in rate base. The key
18 assumptions underlying those projections are:

19 1. MWH Sales (District of Columbia billed distribution)
20 11,872,000 MWH for the 2012 calendar year.

21 2. Sale of Electricity (District of Columbia billed
22 distribution) \$415,000,000 for the 2012 calendar year
23 were projected using budgeted customers by class and
24 the rate per customer authorized in Formal Case No.

1076.

3. Operation & Maintenance Expense (System Distribution - related) \$265,000,000 for the 2012 calendar year.

4. Income Taxes were calculated using currently effective income tax rates.

5. Construction Expenditures \$374,000,000 for the 2012 calendar year.

6. Plant In Service, Accumulated Depreciation, Depreciation Expense, and Property Tax Expense were projected based on forecasted closings to plant.

7. Cash Working Capital was projected using forecasted operating expense activity.

8. Accumulated Deferred Income Taxes are based on projected Schedule M activity.

9. Prepaid Pension/OPEB Liability was projected based on forecasted activity in 2011 and held constant for 2012.

The projections of 2012 operating results and rate base prepared using these key assumptions were first directly assigned or allocated to Pepco's distribution line of business and then to the District of Columbia jurisdiction.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes, it does.

K. M. MCGOWAN
Direct Exhibit
DC P.S.C. - July, 2011

Introduced as:
PEPCO _____ (E)-1

POTOMAC ELECTRIC POWER COMPANY
District of Columbia Cost of Capital
Actual at March 31, 2011

<u>Type of Capital</u>	<u>Percent of Total Capital</u>	<u>Embedded Cost Rate</u>	<u>Weighted Cost Rate</u>
Long Term Debt	50.77%	6.60%	3.35%
Common Equity	<u>49.23%</u>	10.75%	<u>5.29%</u>
Total	<u>100.00%</u>		<u>8.64%</u>

K. M. MCGOWAN
Direct Exhibit
DC P.S.C. - July, 2011

Introduced as:
PEPCO _____ (E)-2

Potomac Electric Power Company

Capital Structure

Actual at March 31, 2011

<u>Type of Capital</u>	<u>Amount</u> (\$ 000's)	<u>Ratios</u>
Long-Term Debt	1,547,800	
Unamortized Net Discount	(8,954)	
Unamortized Debt Issuance Costs	(15,393)	
Unamortized Debt Reacquisition Costs	(32,295)	
Total Long-Term Debt	<u>1,491,158</u>	50.77%
Common Equity	<u>1,445,984</u>	
Total Common Equity	<u>1,445,984</u>	<u>49.23%</u>
Total Capital	<u><u>2,937,142</u></u>	<u><u>100.00%</u></u>

K. M. MCGOWAN
Direct Exhibit
DC P.S.C. - July, 2011

Introduced as:
PEPCO _____ (E)-3

Potomac Electric Power Company
Weighted Cost of Long-term Debt
Long-Term Debt
Actual at March 31, 2011

<u>Security Issue</u>	<u>Coupon Rate</u>	<u>Maturity</u>	<u>Date Issued</u>	<u>Principal Amount</u>	<u>Unamortized Debt Issuance Costs</u>	<u>Unamortized (Premium)/ Discount</u>	<u>Net Amount Outstanding</u>	<u>Effective Cost Rate</u>	<u>Annual Net Cost</u>	<u>Weighted Cost of Debt</u>
<u>First Mortgage Bonds</u>										
	4.95%	11/15/2013	11/24/2003	\$200,000,000	\$555,172	\$179,393	\$199,265,435	5.12%	\$10,202,390	
	4.65%	4/15/2014	3/24/2004	\$175,000,000	\$525,928	\$52,343	\$174,421,729	4.79%	\$8,354,801	
	5.75%	4/15/2034	3/24/2004	\$100,000,000	\$933,291	\$58,251	\$99,008,458	5.90%	\$5,841,499	
	5.40%	6/1/2035	6/1/2005	\$175,000,000	\$1,745,873	\$499,071	\$172,755,056	5.51%	\$9,518,804	
	6.50%	11/15/2037	11/16/2007	\$250,000,000	\$2,906,023	\$552,506	\$246,541,471	6.62%	\$16,321,045	
	6.50%	11/15/2037	3/24/2008	\$250,000,000	\$2,929,974	\$7,430,988	\$239,639,038	6.84%	\$16,391,310	
	7.90%	12/15/2038	12/10/2008	\$250,000,000	\$4,308,400	\$0	\$245,691,600	8.06%	\$19,802,743	
Total First Mortgage Bonds				<u>\$1,400,000,000</u>	<u>\$13,904,661</u>	<u>\$8,772,552</u>	<u>\$1,377,322,787</u>		<u>\$86,432,592</u>	
<u>Tax Exempt Fixed Rate Bonds</u>										
	5.375%	2/15/2024	2/24/1994	\$38,300,000	\$342,653	\$181,690	\$37,775,657	5.64%	\$2,130,547	
	6.20%	9/1/2022	3/17/2009	\$109,500,000	\$1,145,353	\$0	\$108,354,647	6.33%	\$6,858,849	
Total Tax Exempt Fixed Rate Bonds				<u>\$147,800,000</u>	<u>\$1,488,006</u>	<u>\$181,690</u>	<u>\$146,130,304</u>		<u>\$8,989,396</u>	
Long-Term Debt Balance				\$1,547,800,000	\$15,392,667	\$8,954,242	\$1,523,453,091		\$95,421,988	
Unamortized Loss on Debt Reacquisition							(\$32,295,465)		\$2,932,584	
Total Long-Term Debt Balance				<u><u>\$1,547,800,000</u></u>	<u><u>\$15,392,667</u></u>	<u><u>\$8,954,242</u></u>	<u><u>\$1,491,157,626</u></u>		<u><u>\$98,354,572</u></u>	<u>6.60%</u>

K. M. McGowan
Direct Exhibit
DC P.S.C. - July, 2011

Introduced as:
PEPCO _____ (E) -4

Potomac Electric Power Company
Calculation of the Effective Cost Rate of Long-Term Debt

<u>Issue</u>	<u>Coupon Rate</u>	<u>Maturity</u>	<u>Date of Offering</u>	<u>Principal Amount</u>	<u>Offering Price</u>	<u>Original Expense of Issuance</u>	<u>Net Amount to Company</u>	<u>Net Amount Per Unit</u>	<u>Effective Rate</u>
<u>First Mortgage Bonds</u>									
	4.95%	11/15/2013	11/24/2003	\$200,000,000	\$199,318,000	\$2,000,337	\$197,317,663	\$98.66	5.12%
	4.65%	4/15/2014	3/24/2004	\$175,000,000	\$174,826,750	\$1,777,631	\$173,049,119	\$98.89	4.79%
	5.75%	4/15/2034	3/24/2004	\$100,000,000	\$99,125,000	\$1,235,073	\$97,889,927	\$97.89	5.90%
	5.40%	6/1/2035	6/1/2005	\$175,000,000	\$174,380,500	\$2,098,961	\$172,281,539	\$98.45	5.51%
	6.50%	11/15/2037	11/16/2007	\$250,000,000	\$249,377,500	\$3,253,308	\$246,124,192	\$98.45	6.62%
	6.50%	11/15/2037	3/24/2008	\$250,000,000	\$242,292,500	\$3,074,365	\$239,218,135	\$95.69	6.84%
	7.90%	12/15/2038	12/10/2008	\$250,000,000	\$250,000,000	\$4,400,205	\$245,599,795	\$98.24	8.06%
<u>Tax Exempt Fixed Rate Bonds:</u>									
	5.375%	2/15/2024	2/24/1994	\$38,300,000	\$37,877,168	\$1,033,382	\$36,843,786	\$96.20	5.64%
	6.20%	9/1/2022	3/17/2009	\$109,500,000	\$109,500,000	\$1,274,100	\$108,225,900	\$98.84	6.33%

L. J. HOOK
Direct Testimony
DC P.S.C. - July, 2011

Introduced as:
PEPCO _____ (F)

POTOMAC ELECTRIC POWER COMPANY

BEFORE THE
PUBLIC SERVICE COMMISSION OF THE DISTRICT OF COLUMBIA
DIRECT TESTIMONY OF LINDA J. HOOK
FORMAL CASE NO. _____

1 Q. PLEASE STATE YOUR NAME AND POSITION.

2 A. My name is Linda J. Hook. My title is Manager,
3 Revenue Requirements - Pepco. I am testifying on behalf
4 of Potomac Electric Power Company (Pepco or the Company).

5 Q. PLEASE STATE YOUR EDUCATIONAL BACKGROUND AND PROFESSIONAL
6 QUALIFICATIONS.

7 A. I graduated from The Pennsylvania State University
8 in 1977, receiving a degree of Bachelor of Science in
9 Accounting, conferred with Highest Distinction. In 1981,
10 I attained the degree of Master of Business
11 Administration, also from The Pennsylvania State
12 University. I have been employed by Potomac Electric
13 Power Company (subsequently Pepco Holdings, Inc.) since
14 1987, serving in positions of escalating responsibility
15 within the revenue requirements function. I have
16 testified before this Commission in Formal Case Nos. 1053
17 and 1076, and before the Maryland Public Service
18 Commission in Case Nos. 9092 and 9217.

1 Q. WHAT IS THE SCOPE OF YOUR DIRECT TESTIMONY IN THIS
2 PROCEEDING?

3 A. I present the revenue requirement study which
4 demonstrates the need for the \$42,101,000 increase in
5 annual District of Columbia distribution revenues which
6 the Company is requesting in this proceeding. This
7 testimony and the accompanying Exhibits were prepared by
8 me or under my direct supervision. The source documents
9 for my testimony are Company records, public documents,
10 and my personal knowledge and experience.

11 Q. PLEASE SUMMARIZE THE RESULTS OF YOUR REVENUE REQUIREMENTS
12 STUDY.

13 A. As shown at PEPCO (F)-1, page 1, the Company is
14 earning a rate of return of only 6.53% on its fully
15 adjusted rate base; this translates to a return on equity
16 of 6.46%. The requested increase is necessary in order
17 to provide the Company the opportunity to earn the 8.64%
18 return on average rate base discussed in Company Witness
19 McGowan's testimony (PEPCO (E)).

20 Q. WHAT TEST YEAR IS THE COMPANY PROPOSING FOR USE IN THIS
21 PROCEEDING?

22 A. The proposed test year is the twelve months ending
23 September 30, 2011, based on six months' actual data
24 (October, 2010 through March, 2011) and six months'
25 projected data (April, 2011 through September, 2011).

1 Q. PLEASE PROVIDE THE BASIS FOR INCLUDING PROJECTED DATA IN
2 THE PROPOSED TEST PERIOD IN THIS PROCEEDING.

3 A. Commission Rule 200.4 states that "...the proposed
4 test year may include forecasted data provided that the
5 proposed test year does not include more than six (6)
6 months of forecasted data." We have used a partially
7 projected test year because, in the absence of the
8 ability to use a fully projected test year, it provides a
9 more current test period which will be more predictive of
10 the rate effective period than would a fully historical
11 test year. The use of at least a partially projected
12 test year contributes to mitigating the regulatory lag
13 issue discussed by Company Witnesses Kamerick and Lowry,
14 at PEPCO (A) and PEPCO (B), respectively. Further, the
15 use of a partially projected test year is consistent with
16 the Company's presentation in previous rate cases. The
17 Company's application in Formal Case No. 1053 was based
18 on a six months actual, six months projected test year,
19 which the Commission found to be appropriate (Formal Case
20 No. 1053, Order No. 14712).

1 Q. PLEASE DESCRIBE THE KEY ASSUMPTIONS CONTAINED IN THE
2 PROJECTED UNADJUSTED RATEMAKING DATA FOR THE PROPOSED
3 TEST YEAR.

4 A. The key assumptions underlying that portion of the
5 test period based on projected results are as follows:

6 1. MWH Sales (District of Columbia billed
7 distribution) - six months actual of 5,642,548
8 MWH and six months projected of 6,092,536 MWH.

9 2. Sale of Electricity (District of Columbia
10 billed distribution) - six months actual of
11 \$196,099,000 and six months projected of
12 \$214,812,000. Actual revenues reflect the Bill
13 Stabilization Adjustment; projected revenues
14 are based upon budgeted customers by class and
15 the rate per customer authorized in Formal Case
16 No. 1076.

17 3. Other Operation & Maintenance Expense (System
18 Distribution-related) - six months actual of
19 \$175,441,000 and six months projected of
20 \$135,021,000.

21 4. Construction Expenditures - six months actual
22 of \$216,116,000 and six months projected of
23 \$304,491,000.

24 5. Income Taxes - are computed at currently
25 effective rates.

1 Q. PLEASE DESCRIBE THE PROCEDURES EMPLOYED IN THE
2 PREPARATION OF THE PROJECTED DATA.

3 A. The six months of projected data were based on the
4 Company's 2011 budgeted data. The projected data were
5 combined with six months actual data, then directly
6 assigned and/or allocated as applicable first to the
7 Company's distribution business, then to the District of
8 Columbia jurisdiction.

9 Q. HAVE YOU PREPARED AN EXHIBIT THAT SUPPORTS THE COMPANY'S
10 RATE INCREASE REQUEST?

11 A. Yes. PEPCO (F)-1 presents the necessary financial
12 and accounting data for the test period ending September
13 30, 2011, which supports the Company's requested increase
14 in annual revenues.

15 Q. PLEASE SUMMARIZE THE CONTENTS OF PEPCO (F)-1.

16 A. Page 1 presents the Company's unadjusted and
17 adjusted District of Columbia jurisdictional results of
18 operation, for the provision of distribution service, for
19 the twelve months ending September 30, 2011. The revenue
20 requirement necessary to achieve the 8.64% rate of return
21 on rate base supported by Witness McGowan is also
22 presented.

23 A summary of the ratemaking adjustments is presented
24 on pages 2-4; pages 5 through 44 present the detailed
25 derivation of each of the ratemaking adjustments, along

1 with any associated tax effect.

2 Page 45 presents the impact of interest
3 synchronization on unadjusted rate base.

4 Page 46 presents the revenue requirement associated
5 with each individual ratemaking adjustment.

6 Page 47 shows the detailed computation of the cash
7 working capital allowance included in rate base.

8 Page 48 presents the statutory tax rates and
9 associated gross-up factors used in determining the
10 Company's revenue requirement.

11 The Company's March 31, 2011 capital structure and
12 associated cost rates that were used in deriving the
13 District of Columbia jurisdictional revenue requirement
14 presented at page 1 of PEPCO (F)-1 (line 15, column 4)
15 are discussed by Company Witness McGowan at PEPCO (E) and
16 Company Witness Hevert at PEPCO (D).

17 **Q. PLEASE DISCUSS THE DEVELOPMENT OF PEPCO'S COST OF SERVICE**
18 **ON A DISTRIBUTION-ONLY BASIS.**

19 **A.** Amounts presented in this proceeding relate only to
20 Pepco's regulated distribution operations. The financial
21 records of the Company are not presented on a
22 distribution-only basis, however; rather, they consist of
23 costs associated with the Standard Offer Service (SOS),
24 transmission, and distribution lines of business. The
25 basis for developing Pepco's distribution-only cost of

1 service from all-encompassing financial records is the
2 distribution accounts as specified in the Federal Energy
3 Regulatory Commission (FERC) Uniform System of Accounts.
4 The majority of costs, on both the plant side and the
5 expense side, are contained in FERC Accounts that are
6 specific to function.

7 Distribution plant costs are those costs contained
8 in the FERC distribution accounts, numbers 360 to 373.
9 Distribution expense costs are those costs contained in
10 the FERC distribution accounts (inclusive of Customer
11 Accounts Expenses, Customer Service and Informational
12 Expenses, and Sales Expenses), numbers 580 through 916.
13 The exception to this is Account 904, Uncollectible
14 Accounts, which has to be functionalized. Transmission
15 plant costs are from the FERC transmission accounts,
16 numbered 350 to 359. Transmission expense costs are those
17 costs contained in the FERC transmission accounts,
18 numbers 560 through 573.

19 Other costs, such as General Plant and
20 Administrative and General Expenses, are not contained in
21 FERC accounts that are specific to transmission and
22 distribution functions and thus have to be functionalized
23 to produce the distribution-related portion of these
24 costs.

1 Q. HAVE YOU PREPARED AN EXHIBIT WHICH SUMMARIZES TOTAL
2 SYSTEM AND DISTRIBUTION-ONLY COST OF SERVICE ELEMENTS?

3 A. Yes. PEPCO (F)-2, page 1 of 3, presents a listing
4 of rate base and operating income elements on both a
5 system and a distribution-only level. Pages 2-3 of that
6 Exhibit provide a short description of the method used to
7 identify the distribution-related portion of these costs.
8 The method used to determine distribution-related cost of
9 service is consistent with that used by the Company and
10 accepted by the Commission in Formal Case Nos. 1053 and
11 1076.

12 Q. IS THE REVENUE REQUIREMENT STUDY AND COST OF SERVICE
13 REFLECTED IN PEPCO (F) IN CONFORMANCE WITH PAST
14 COMMISSION RATEMAKING DETERMINATIONS?

15 A. Yes. The operating results presented in PEPCO (F)
16 are based upon past Commission ratemaking determinations.
17 Unadjusted rate base is presented on a thirteen-month
18 average basis. Rate base has been reduced by the amount
19 of customer deposits in account 235; Plant Held for
20 Future Use was also excluded from rate base, consistent
21 with the Commission's decision in Formal Case No. 929.
22 Rate base includes plant materials and operating
23 supplies, net of related accounts payable, as approved in
24 Formal Case No. 905. Also included is the net average
25 balance of the Company's prepaid pension asset/other post

1 employment benefit (OPEB) liability, net of associated
2 accumulated deferred income taxes, which the Commission
3 determined to be "consistent with Commission precedent"
4 in Formal Case No. 1053. (Order No. 14712, page 48.)

5 Q. PLEASE DISCUSS THE RATEMAKING ADJUSTMENTS WHICH ARE
6 SUMMARIZED ON PEPCO (F)-1, PAGES 2-4, AND PRESENTED IN
7 DETAIL AT PAGES 5 THROUGH 44.

8 A. The ratemaking adjustments reflected in the
9 September 30, 2011 test period are as follows:

10 Adjustment 1 includes the impact of the average
11 balance of District of Columbia distribution projects that
12 are complete, are in service, and are thus used and useful
13 to customers, but which have not been transferred from
14 construction work in progress (CWIP) to electric plant in
15 service (EPIS) in the financial records of the Company. In
16 approving this treatment in Formal Case No. 1053, Order
17 No. 14712 (pages 30-31), the Commission noted that:

18 Under Commission precedent, the rate base of a
19 utility can properly include the cost of a
20 construction project that is in service during
21 the test period and, in appropriate
22 circumstances, a project completed outside the
23 test period, as long as its in-service date is
24 not too remote in time from the test period.
25 In this case, the evidence reflects that the
26 projects covered by RMA no. 23 were complete
27 and in-service during the test year, and were
28 not included in the Company's EPIS records
29 because they were awaiting either final
30 accounting treatment to EPIS or the proper
31 recording of all project costs. In other
32 words, the projects were not merely being

1 constructed, but rather were already in service
 2 and meeting customer needs during the test
 3 year. In such circumstances, allowing the
 4 proposed adjustments to the rate base is
 5 consistent with our ruling in Formal Case No.
 6 1016, where we stated that 'it is reasonable to
 7 allow the costs of construction projects to be
 8 included in rate base when projects are in fact
 9 placed in service before the end of the test
 10 year, but are not recorded as being test year
 11 plant in service because of delays in booking.'
 12 FC No. 1016, Order No. 12986 at paragraph 187
 13 (Nov 10, 2003).

14 Adjustment 2 adjusts rate base and operating
 15 expenses to include expenditures associated with two
 16 sub-transmission projects that will be completed and
 17 serving customers within twelve months of the end of the
 18 test period: the construction of a distribution
 19 transformer at the Company's Benning Road site, and the
 20 upgrade of the Ritchie - Central Avenue 69kV lines.
 21 Company Witness Gausman provides details regarding
 22 project costs and scheduling, as well as the need for
 23 these projects, at PEPCO (I).

24 Because this Benning Road transformer will be placed
 25 in service within twelve months of the end of the test
 26 period, EPIS has been adjusted to reflect the full value
 27 of the investment. Depreciation expense for the first
 28 year of service has been included, as has the first year
 29 average balance of accumulated depreciation. Accumulated
 30 deferred taxes have also been adjusted to reflect the

1 difference between tax and book depreciation; it has been
2 assumed that this project will be eligible for 50% bonus
3 depreciation.

4 In approving identical treatment for the Northeast
5 substation in Formal Case No. 1053, the Commission
6 stated:

7 On a case-by-case basis, the Commission has
8 allowed the rate base to include the cost of
9 construction work completed outside the test
10 period in certain 'unique and compelling'
11 circumstances, including situations where (1)
12 the project's completion date is not too remote
13 in time from the test period; (2) the cost of
14 the project is reasonable; and (3) the project
15 will clearly be beneficial (i.e., 'used and
16 useful') to ratepayers during the entire rate-
17 effective period. (Order No. 14712, page 43.)
18

19 This adjustment reflects a known and certain change which
20 will take place within twelve months of the end of the
21 test year. As discussed by Company Witness Gausman at
22 PEPCO (I), the project's cost is reasonable and it will
23 be beneficial to customers during the period in which
24 rates set in this proceeding will be in effect. Thus, it
25 is appropriate that its full value be reflected in cost
26 of service.

27 As discussed by Company Witness Gausman, the Ritchie
28 - Central Avenue 69 kV line upgrade will be placed in
29 service by the fall of 2011 at the latest, and thus will
30 be in service before the end of the test year. Again,
31 because the plant addition will be in service and serving

1 customers the entire rate effective period, it is
2 appropriate to reflect the full value of the investment
3 in cost of service.

4 Adjustment 3 includes in cost of service costs
5 associated with a major upgrade to the Energy Management
6 System (EMS) at Pepco's Control Center facility. This
7 upgrade, the purpose of which is discussed by Company
8 Witness Gausman in his testimony at PEPCO (I), is being
9 amortized over the remaining life of the Control Center
10 lease, which terminates in December 2019.

11 Adjustment 4 is the first of four adjustments
12 related to implementation of the Advanced Metering
13 Infrastructure (AMI) in the District of Columbia.
14 Implementation of AMI, which was approved by the
15 Commission in Formal Case No. 1056, is discussed in
16 detail in the testimony of Company Witness Gausman at
17 PEPCO (I). Adjustment 4 reflects in cost of service the
18 full value of the new AMI Smart Meters, installation of
19 which began in October 2010 and is scheduled to be
20 completed in the District of Columbia by the end of 2011.

21 Q. PLEASE DISCUSS HOW THE DEPLOYMENT OF THE SMART METERS IS
22 RECORDED IN THE FINANCIAL RECORDS OF THE COMPANY.

23 A. The cost of procuring and installing the AMI meters,
24 net of any Department of Energy reimbursement, is
25 recorded in account 107, CWIP upon acquisition. Upon

1 installation, the net AMI cost is transferred from
2 account 107 to account 101, EPIS; specifically, it is
3 recorded in account 370.1, a sub-account of FERC meter
4 account 370, to assure segregation of the net AMI cost.
5 At this time, depreciation of the AMI asset begins.
6 Currently the AMI meters are being depreciated at the
7 rate set for account 370 in Formal Case No. 1053
8 (Depreciation Study as of 12/31/2007), which is 2.75%.

9 The Company has previously proposed that the new
10 meters be depreciated over a 15-year life; until such
11 time as the Commission formally approves that rate
12 however, depreciation is being recorded at the rate
13 approved for non-AMI meters in Formal Case No. 1053.

14 As AMI meters are installed, a retirement of non-AMI
15 meters is recorded in account 370 and depreciation of the
16 non-AMI meters stops. The retirement results in a loss
17 (the remaining net book value of the non-AMI meter
18 asset). The loss is initially recorded on the Company's
19 income statement, and is then reclassified as a
20 regulatory asset on the Company's balance sheet. The
21 recovery of this regulatory asset is reflected in
22 Adjustment 6.

23 Q. PLEASE DISCUSS THE IMPACT OF THIS ACCOUNTING ON
24 RATEMAKING ADJUSTMENT NO. 4.

25 A. Because of the above-discussed accounting, a portion

1 of the cost of AMI meters is embedded in unadjusted cost
2 of service in 13-month average EPIS, accumulated
3 depreciation, and accumulated deferred taxes, and in
4 depreciation expense. Adjustment 4 annualizes these
5 amounts to reflect the full value, net of DOE
6 reimbursement, of the fully deployed Smart Meters.

7 Q. PLEASE CONTINUE THE DISCUSSION OF THE REMAINING
8 AMI-RELATED ADJUSTMENTS.

9 A. Adjustment 5 reflects the costs associated with the
10 AMI Communications Network and related software that will
11 be in service and serving customers within a reasonable
12 time from the end of the test period. This includes
13 communications equipment which will be recorded in
14 general plant and depreciated over 15 years, and Customer
15 Benefit System Integration (CBSI) software that will be
16 amortized over the normal software life of 5 years. Also
17 included in this adjustment is the cost of software
18 projects which will serve Delmarva Power & Light Company
19 as well as Pepco, and which are thus recorded in the
20 financial records of the PHI Service Company. Again,
21 this software is amortizable over 5 years, with the
22 amortization expense charged to the utilities based on
23 their respective customer counts.

24 Adjustment 6 adjusts cost of service to reflect
25 commencement of recovery of AMI costs which have been

1 deferred in regulatory assets. The adjustment has four
2 components, the largest of which is the loss on early
3 retirement of non-AMI meters discussed previously. The
4 adjustment also reflects two elements associated with the
5 depreciation expense differential between non-AMI and
6 Smart Meters.

7 First, as the non-AMI meters are retired and
8 replaced with Smart Meters, the amount of depreciation
9 expense being recorded on the remaining non-AMI meters
10 becomes less than the level of such depreciation pre-
11 deployment, and less than the level of depreciation
12 reflected in rates established in Formal Case No. 1076.
13 In effect, the Company is recovering more meter
14 depreciation in current rates than is now being recorded.
15 The customer is being given credit for this differential,
16 as shown on line 2 of PEPCO (F)-1, page 10 of 48. Second,
17 depreciation of the new AMI meters is included. Due to
18 the lower cost of the Smart Meters, resulting in part
19 from DOE reimbursement, depreciation on the new meters
20 does not offset the reduction to the regulatory asset
21 created by depreciation of the declining balance of the
22 old meters.

23 The final component of the regulatory asset recovery
24 reflected in Adjustment 6 is that of incremental costs
25 incurred after December 31, 2008. The nature and timing

1 of these costs are discussed by Company Witness Gausman
2 at PEPCO (I).

3 Because the regulatory asset being recovered
4 includes a return component, assumptions had to be made
5 regarding the timing of when recovery would begin in
6 computing Adjustment 6. Based on the filing date of this
7 application and the Commission's goal of completing base
8 rate proceedings within a nine-month time frame, it was
9 assumed that incremental costs, including the return
10 component, would build through March 31, 2012, after
11 which time recovery over a fifteen-year period was
12 assumed to commence.

13 Adjustment 7 is the final of the four AMI-related
14 adjustments. It is presented to reflect the on-going
15 level of AMI-related savings, net of on-going incremental
16 costs, as discussed by Company Witness Gausman.

17 Q. PLEASE DISCUSS THE REMAINING NON-AMI ADJUSTMENTS.

18 A. Adjustment 8 adjusts cost of service to reflect the
19 2011 level of pension and other post-employment benefit
20 (OPEB) costs based on the most recently available
21 information from the Company's independent actuary,
22 Towers Watson. Consistent with treatment approved in
23 Formal Case No. 1053, Order No. 14712, Adjustment 8
24 adjusts rate base to reflect the 2011 level of
25 distribution-related, District of Columbia allocated

portion of Pepco's net of tax prepaid pension asset/OPEB liability. Also consistent with treatment approved in Formal Case No. 1053, Adjustment 8 adjusts operating income to reflect the 2011 pension and OPEB expense incurred by Pepco, including both expense direct to Pepco and the Pepco portion of such expense related to Service Company employees. The Pepco portion of the Service Company net of tax prepaid pension asset/OPEB liability has also been included in rate base.

In Formal Case No. 1076, due to an extraordinary fluctuation in the level of pension expense in the time frame of that case, the Commission deviated slightly from this treatment:

Therefore, for this case and this case only, Pepco's pension costs will be estimated for the rate-effective period based on a two-year average of actual pension costs. The prepaid pension asset will, for this proceeding only, likewise be calculated based on a two year average (2008-2009). The Commission's decision on these two adjustments shall not be viewed as precedent going forward. (Order No. 15710, page 49.)

Because no such drastic fluctuation in the level of expense exists presently, the Company has used in this case the treatment previously approved, i.e., to reflect costs associated with employee pension and OPEB expenses based on the most recently available information from the Company's independent actuary, Towers Watson.

1 Adjustment 9 proposes recovery of additional taxes
 2 related to a change in the law regarding Medicare Part D.
 3 As discussed by Company Witness Winston at PEPCO (H), the
 4 Patient Protection and Affordable Care Act, which became
 5 law in March, 2010, resulted in a deferred tax charge to
 6 Pepco's Federal income tax expense. Based on precedent
 7 of the Commission's including in rates cost changes
 8 resulting from tax law changes (for example, when the
 9 Federal income tax rate decreased from 46% to 34%
 10 (subsequently increased to 35%)), the charge to tax
 11 expense was deferred in the financial records of the
 12 Company until such time as it could be included in cost
 13 of service in the context of a base rate proceeding.

14 Prior to the change in law, customers benefitted
 15 from the tax-free subsidy, because it was flowed through
 16 to customers as a reduction to taxable income, thereby
 17 reducing the tax expense reflected in cost of service in
 18 both Formal Case Nos. 1053 and 1076. The Company is now
 19 requesting that the increase in tax expense due to the
 20 change in law be recovered from customers. Adjustment 9
 21 proposes recovery of the amount over a three-year period,
 22 with the unamortized balance reflected in rate base.

23 Adjustment 10 reflects the exclusion of certain wage
 24 increase and gain sharing costs disallowed in Formal Case
 25 No. 939, Order No. 10646.

1 Adjustment 11 excludes from cost of service the
2 costs associated with supplemental executive retirement
3 plans, as ordered by the Commission in Formal Case No.
4 939, Order No. 10646.

5 Adjustment 12 reflects the exclusion of incentive
6 plan payments in accordance with the Commission's
7 decision in Formal Case No. 1053, Order No. 14712.

8 Adjustment 13 adjusts amortization expense and rate
9 base for the impacts of known and certain changes to
10 software amortization in the rate effective period,
11 consistent with the treatment in Formal Case Nos. 939,
12 1053, and 1076.

13 Adjustment 14 adjusts cost of service to remove
14 amounts associated with the portion of physically removed
15 69 kV lines over National Park Service land, as ordered
16 in Formal Case No. 1076, Order No. 15710.

17 Adjustment 15 adjusts cost of service to remove the
18 impact of Formal Case No. 1053 costs, the amortization of
19 which ended during the test period.

20 Adjustment 16 adjusts rate base to reflect continued
21 amortization of the outside counsel and consulting costs
22 incurred in Formal Case No. 1076. Rate base is adjusted
23 to reflect the average unamortized balance for the rate
24 effective period, similar to the treatment of Formal Case
25 No. 1053 amortization approved by the Commission in Order

1 No. 15710, in Formal Case No. 1076.

2 Adjustment 17 adjusts cost of service to defer and
3 amortize similar costs associated with this proceeding
4 over a three-year amortization period, consistent with
5 Commission treatment of similar costs in Formal Case Nos.
6 1053 and 1076 (Order Nos. 14712 and 15710, respectively).

7 Adjustment 18 reflects the continued amortization of
8 costs associated with the Customer Education Advisory
9 Board-sponsored two-year campaign to educate District of
10 Columbia consumers about deregulation and customer
11 choice. These costs, which were incurred by Pepco
12 pursuant to the Commission's directive in Formal Case No.
13 945, Phase II, Order No. 13275, are being recovered over
14 a three-year period as approved in Formal Case No. 1076,
15 Order No. 15710.

16 Adjustment 19 reflects continued amortization over a
17 fifteen-year period of AMI-related costs incurred through
18 December 31, 2008, as approved in Formal Case No. 1076,
19 Order No. 15710.

20 Adjustment 20 adjusts cost of service to reduce the
21 amortization of flotation costs associated with the
22 November, 2008 common stock issuance. The amortization
23 of these costs will end in mid-2012, so cost of service
24 has been adjusted to reflect the levels that will be
25 experienced in the twelve month period following the

September test period.

Adjustment 21 adjusts rate base and operating income to reflect inclusion of Pepco's share of the costs associated with PHI's new \$1.5 billion credit facility effective August 1, 2011. The credit facility supports the issuance of commercial paper (short-term debt) on an as-needed basis, assuring investors and rating agencies that the Company has a committed line of credit with banks in the event of a liquidity problem. In approving inclusion of costs associated with the old facility in Formal Case No. 1076, the Commission noted that the facility is beneficial to customers:

It has allowed the Company to access the capital and credit markets to meet its daily working requirements on less expensive terms. Balancing the interest of ratepayers and the Company, and recognizing the importance of Pepco's ability to raise capital on reasonable terms, the Commission approves the Company's adjustment and will permit the Company to recover start-up costs and annual maintenance fees. F.C. 1076, Order 15710, p. 37.

Adjustment 22 adjusts operation and maintenance expense to annualize employee salary and wage increases which occurred during the test year (March 1, 2011 for management employees and May 31, 2011 for union/bargaining unit employees). Also included are projected increases for management and union employees which will take place within twelve months of the end of

the test year. As shown at lines 2, 3, 6, and 7 of Exhibit PEPCO (F)-1, page 26 of 48, the base upon which the increase is applied has been adjusted to remove any incremental labor associated with major storm restoration activities, as directed by the Commission in Order No. 15710, Formal Case No. 1076. The wage increases have been adjusted to take into account changes in employee levels, consistent with the treatment approved in Formal Case Nos. 1053 and 1076 (Order Nos. 14712 and 15710, respectively).

Adjustment 23 adjusts operation and maintenance expense to reflect changes in employee health and welfare costs in the rate effective period, consistent with the treatment approved in Formal Case Nos. 1053, and 1076 (Order Nos. 14712 and 15710, respectively). Costs associated with medical, dental, and vision plans are adjusted to reflect anticipated percentage increases developed by PHI's Human Resources department, based on analysis of health care cost trends in the Mid-Atlantic region supplied Lake Consulting, Inc.

Adjustment 24 reflects in cost of service the increase in customer care costs resulting from various programs being undertaken by Pepco to enhance customer service. The adjustment includes: annualization of personnel costs for additional employees hired during the

test year, reflection of costs associated with telecommunications infrastructure improvements, annualization of costs associated with the Company's improved emergency preparedness strategy, and inclusion of costs associated with customer education and ongoing market research in relation to emergency preparedness. The nature and importance of these various programs are discussed by Company Witness Dickerson at PEPCO (J).

Adjustment 25 adjusts operating expenses to reflect a three-year average amount of regulatory expense, consistent with the Commission's decisions in Formal Case Nos. 905, 912, 929, 939, 1053, and 1076.

Adjustment 26 normalizes operation and maintenance expense associated with storm restoration efforts to their three-year average level, consistent with treatment approved in Formal Case No. 1053, Order No. 14712.

Adjustment 27 reduces operation and maintenance (O&M) expense for the PHI-wide organizational review project (ORP) and corporate restructuring undertaken in the latter part of 2010, discussed by Company Witness Kamerick at PEPCO (A). The net result of the restructuring is approximately \$28 million in annual savings in the PHI Corporate Center and Support Services areas, approximately \$9.6 million of which will be seen in Pepco Power Delivery (i.e., transmission and

1 distribution) O&M. Because the savings did not begin
2 until the first quarter of 2011, the last quarter of 2010
3 must be adjusted to reflect the impact of savings that
4 will continue throughout the rate effective period.

5 Adjustment 28 adjusts cost of service to properly
6 reflect Pepco's share of ORP-related severance costs.
7 The entire severance expense from which ORP savings inure
8 was recorded in the fourth quarter of 2010. Because ORP-
9 related savings will produce benefits for several future
10 periods, it is both appropriate and in conformance with
11 Commission precedent to amortize related severance
12 payments over future periods. (Formal Case No. 939, Order
13 No. 10646.) Adjustment 28 reduces O&M expense for the
14 severance recorded in Quarter 4, and amortizes that
15 amount over a three-year period, with the average
16 unamortized balance reflected in rate base.

17 Adjustment 29 increases O&M expense to reflect the
18 increasing cost of acquiring fuel for the Company's
19 vehicles. Fuel costs have increased dramatically over
20 the level incurred in the actual months of the test
21 period as well as the budgeted amount embedded in the six
22 projected months. The Company uses two types of fuel in
23 its vehicles-regular unleaded and a biodiesel blend
24 ("B-10 Blend"), which is comprised of 10% biofuel and 90%
25 ultra-low-sulfur diesel. The average price per gallon

for these fuels reflected in the six months actual, six months projected test period was \$2.96 for unleaded, and \$3.11 for the B-10 Blend. Actual May 2011 prices were \$3.80 and \$3.71, respectively, based on the invoice price for fuel purchased for Pepco's internal refueling sites.

Adjustment No. 29 re-prices actual usage in the test period at the latest available (May 2011) invoiced prices. This treatment is not dissimilar to the way fuel prices were historically treated prior to deregulation and the divestiture of the Company's generating stations; fuel stock inventory was generally reflected in rate base at 13-month average quantities, re-priced at end of period prices, on the theory that those prices will likely be more representative of what will occur in the rate effective period.

Adjustment 30 adjusts cost of service to include \$500,000 required for additional vegetation management expenditures in the District of Columbia. Company Witness Gausman discusses the nature of this additional expenditure and the need for it in his testimony at PEPCO (I).

Adjustment 31 reflects exclusion of test-period adjustments to deferred compensation, consistent with the Commission's decision in Formal Case No. 1053, Order No. 14712.

1 Adjustment 32 removes from cost of service certain
2 employee benefit costs associated with employee
3 association activities, as directed in Order No. 15710 in
4 Formal Case No. 1076.

5 Adjustment 33 removes from test-year operating
6 expense the costs associated with industry memberships
7 and contributions, except for those associated with the
8 American National Standards Institute, which were
9 specifically allowed by the Commission in Formal Case No.
10 889 (Order No. 9509).

11 Adjustment 34 removes from the test period the
12 expenses associated with institutional and promotional
13 advertising, consistent with the Commission's rules and
14 longstanding Commission precedent. Any advertising
15 expenditures remaining in the test period are associated
16 with advertising which is informational in nature--the
17 costs of which are therefore properly included in the
18 cost of service. PEPCO (F)-7 presents a detailed
19 analysis of informational advertising expenditures for
20 the historical test year ended March 31, 2011 and the
21 projected test year ending September 30, 2011.

22 Adjustment 35 removes from cost of service a
23 December 2010 charge to O&M for future environmental
24 remediation required at PHI's Benning Road facility. The
25 expense is related to the oil-fired generation facility

at Benning which, although presently owned by Pepco Energy Services (PES), was owned and operated by Pepco for many years prior to its transfer to PES in 2001. The entire PHI-recognized expense of \$13.5 million was apportioned between Pepco and PES, then further assigned within Pepco to generation, transmission, and distribution based on the time frame the facility was owned by Pepco versus PES. Due to uncertainty regarding the final cost of remediation as well as the potential for partial insurance reimbursement, the Company is not requesting recovery of this expense at this time. We would ask the Commission, however, to approve deferral of the costs in a regulatory asset for review in a future proceeding.

Adjustment 36 increases operation and maintenance expense, in accordance with past practice and Commission precedent, to reflect interest expense related to the average level of customer deposits at the 2011 rate of .25%. In Formal Case No. 748, the Commission determined that customer deposits constitute a customer-supplied source of capital which should be deducted from rate base. The Commission also found it appropriate to adjust operating expense to reflect the interest paid on such deposits (Formal Case No. 748, Order No. 7457). Income tax expense has been adjusted accordingly.

Adjustment 37 adjusts cost of service for the increase in District of Columbia Water and Sewer Authority (WASA) rates charged to the Company that will become effective October 1, 2011. Although the new rate schedule reflects modest increases in variable rates assessed based on consumption, the fixed fee for the Clean Rivers Impervious Area Charge nearly doubled. The estimated increase reflected in the adjustment was computed by applying the new rates to the Company's fiscal year 2010 (October 1, 2009 - September 30, 2010) water consumption and billable ERU's (equivalent residential units, which are the basis for the impervious surface charges).

Adjustment 38 reflects in cost of service the impact of newly implemented steel plate fees assessed by the D.C. Department of Transportation pursuant to D.C. Law 18-223, Title VI, Subtitle D. entitled, the "Steel Plate Fee Amendment Act of 2010." The new fees, based on the law in effect at the time this filing was prepared, add approximately \$9.5 million to District of Columbia distribution-related capital projects that is not reflected in either the historical test year or the budget that was used for the projected months. The ratemaking adjustment adds the additional \$9.5 million to District of Columbia EPIS, as well as makes corresponding

1 adjustments to depreciation expense, accumulated
2 depreciation, and accumulated deferred taxes.

3 Adjustment 39 adjusts cost of service to include
4 flotation costs for a 2012 common stock issuance. The
5 exact details of the issuance have not been finalized,
6 therefore, the actual cost assigned to Pepco for the
7 November 2008 issuance, which was approved for recovery
8 in Formal Case No. 1076, has been used as a proxy.
9 Ratemaking Adjustment 39 assumes the same two-year
10 amortization period, with the average unamortized costs
11 reflected in rate base, as approved by the Commission in
12 Order No. 15864 (Order on Reconsideration) in Formal Case
13 No. 1076.

14 Adjustment 40 adjusts District of Columbia and
15 Federal income tax expense to reflect the impact on
16 synchronized income taxes of the ratemaking adjustments
17 to rate base. Pursuant to longstanding Commission
18 precedent, the interest expense used for computing income
19 taxes must be synchronized with that inherent in the
20 Company's return on rate base. Historically, the Company
21 has accomplished this using one ratemaking adjustment.
22 However, to better align unadjusted versus adjusted
23 operating results, it is more appropriate to reflect the
24 impact of interest synchronization related to unadjusted
25 rate base in the unadjusted column. The impact on taxes

1 of the effect of interest synchronization related to
2 unadjusted rate base, which is now reflected in the
3 unadjusted column of PEPCO (F)-1, page 1, lines 20 and
4 21, is presented at page 45 of that Exhibit.

5 Q. PLEASE DISCUSS THE COMPANY'S CASH WORKING CAPITAL
6 COMPONENT OF RATE BASE.

7 A. Cash working capital allowance refers to the amount
8 of investor-supplied capital required to carry out the
9 Company's day-to-day operations. To the extent a
10 differential exists between when the Company receives
11 revenue for the services it provides (as measured by its
12 revenue lag) and when it must pay for expenses incurred
13 in providing those services (as measured by its expense
14 lag), there is a need for operating funds. Because
15 these funds are provided by the Company's investors, they
16 are included as a component of rate base.

17 Q. HOW WAS THE COMPANY'S CASH WORKING CAPITAL ALLOWANCE
18 COMPUTED?

19 A. The level of working capital allowance is determined
20 by applying the Company's net lag days, or the difference
21 between its revenue lag and its expense lag, to the
22 average daily expense incurred in the test period.

1 Q. HAVE YOU PROVIDED AN EXHIBIT DEMONSTRATING THE DERIVATION
2 OF THE CASH WORKING CAPITAL ALLOWANCE?

3 A. Yes. This calculation is presented at PEPCO (F)-1,
4 page 47. As shown on this Exhibit, the Company's
5 composite District of Columbia revenue lag for the twelve
6 months ending September 30, 2011 was 52.66 days. This is
7 a weighted average, representing both Sale of Electricity
8 (based upon application of the appropriate class of
9 business lag days to billed District of Columbia
10 distribution revenues for the test period) and Other
11 Revenues. The Company's composite expense lag was 30.43
12 days, and was derived by applying the lag days for each
13 type of expense to District of Columbia expenses for the
14 twelve months ending September 30, 2011. The result is a
15 net lag of 22.23 days, which when applied to average
16 District of Columbia daily expenses of \$641,093, results
17 in a District of Columbia working capital allowance of
18 \$14,251,497.

19 Q. IS THAT THE FINAL CASH WORKING CAPITAL ALLOWANCE YOU ARE
20 RECOMMENDING FOR INCLUSION IN RATE BASE?

21 A. No. Consistent with past Commission practice, two
22 additional adjustments must be made. First, \$101,465 of
23 District of Columbia-allocated withholding taxes is
24 removed, in recognition of the fact that the Company has
25 the use of employee payroll withholdings from the payroll

1 date until the funds are remitted to the government.
2 Second, the Company's District of Columbia-allocated
3 imprest funds requirement of \$183,162 is added. With
4 these adjustments, the working capital allowance
5 reflected in the Company's unadjusted rate base is
6 \$14,333,194.

7 Q. WHAT WAS THE BASIS OF THE LAG DAYS USED IN THE
8 COMPUTATIONS SHOWN AT PEPCO (F)-1, PAGE 47?

9 A. The revenue and expense lag days used in determining
10 the Company's cash working capital allowance were
11 determined in the 2005 detailed lead-lag study filed and
12 approved in Formal Case No. 1053. Although that study
13 was performed over five years ago, there have been no
14 changes, for example in the Company's invoice processing,
15 which would have materially impacted the lag days. An
16 updated study will be performed upon the completed
17 implementation of AMI and the full deployment of Smart
18 Meters in the District of Columbia.

19 Q. IN ACCORDANCE WITH THE COMMISSION'S DECISIONS IN FORMAL
20 CASE NOS. 869, 889, 905, 912, 929, AND 939, DOES THE TEST
21 YEAR COST OF SERVICE INCLUDE ANY LEGAL EXPENSES
22 ASSOCIATED WITH SETTLED DISCRIMINATION CASES?

23 A. No. Consistent with Commission precedent, the test
24 year cost of service contains no legal expenses
25 associated with settled discrimination cases.

1 Q. WHAT IS THE PURPOSE OF PEPCO (F)-3?

2 A. Commission Rule 200.1 (a) requires that a statement
3 of an historical test year and the basis for choosing
4 that test year be included with the rate change
5 application. Schedules similar to the ones presented in
6 PEPCO (F)-1 are presented in PEPCO (F)-3 for the twelve
7 months ended March 31, 2011. This period was chosen as a
8 recent historical period for which distribution-only
9 jurisdictional data are available.

10 Q. WHAT IS THE PURPOSE OF PEPCO (F)-4?

11 A. Commission Rule 200.5 (d) requires that an analysis
12 of changes in jurisdictional rate base, jurisdictional
13 expenses, and jurisdictional operating income between the
14 historical test year and the proposed test year be
15 provided when a utility submits forecasted data as part
16 of its proposed test year data. PEPCO (F)-4 provides such
17 an analysis.

18 Q. WHAT IS THE PURPOSE OF PEPCO (F)-5?

19 A. Commission Rule 200.3 (h) requires a rate change
20 application to include the most recent historic balance
21 sheet available as of the date of the filing. A balance
22 sheet as of March 31, 2011 has been provided on pages 1
23 through 8 of PEPCO (F)-5. Note that the amounts presented
24 reflect total Pepco; a distribution-only balance sheet is
25 not available.

1 Q. WHAT IS THE PURPOSE OF PEPCO (F)-6?

2 A. PEPCO (F)-6 sets forth the Company's regulatory
3 expense related to matters before the Commission for the
4 twelve months ending September 30, 2011. The schedule
5 shows amounts expended by the Company arising from
6 assessments by the Commission and the People's Counsel.
7 This Exhibit also provides similar expenses for the three
8 years preceding the test period as required by Order No.
9 7135 in Formal Case No. 715.

10 Q. DO YOU HAVE ANY ADDITIONAL COMMENTS REGARDING THE
11 REQUESTED INCREASE IN THIS CASE?

12 A. Yes. As discussed by Company Witnesses Kamerick and
13 Lowry at PEPCO (A) and PEPCO (B), respectively, the
14 Company's return on equity has been substantially below
15 its allowed ROE for a very long time. This is
16 demonstrated by the fact that, even in the reporting
17 periods immediately following the implementation of new
18 rates, the Company has historically not earned its
19 authorized rate of return, on either an unadjusted or
20 fully adjusted basis.

21 Q. HAVE YOU PREPARED AN EXHIBIT WHICH DEMONSTRATES THIS?

22 A. Yes. I have prepared PEPCO (F)-8, a two-page
23 Exhibit which demonstrates this.

1 Q. PLEASE DISCUSS PEPCO (F)-8.

2 A. Page 1 of PEPCO (F)-8 presents a table showing, on
 3 both an unadjusted and fully adjusted basis, rate base,
 4 operating income, actual earned ROE, and revenue
 5 deficiency for the 6&6 test period, the historical test
 6 period, and the nine calendar years preceding the test
 7 periods. For years prior to implementation of the Bill
 8 Stabilization Adjustment, the unadjusted results have
 9 been adjusted to reflect weather normalization. The
 10 adjusted results reflect any and all other ratemaking
 11 adjustments, including the annualization of any rate
 12 increases.

13 As demonstrated by PEPCO (F)-8, page 1, the Company
 14 has been unable to earn its authorized ROE for the entire
 15 time period examined.

16 Page 2 of PEPCO (F)-8 carries this scenario one step
 17 further, by presenting the results of a fully projected
 18 2012 test year. The starting point for this Exhibit was
 19 Pepco distribution-related results for the District of
 20 Columbia, as provided by Company Witness McGowan, and
 21 discussed by him at PEPCO (E). (See column 1 of PEPCO
 22 (F)-1, page 1.) These results had to be adjusted to
 23 remove items that are reflected in the financial model,
 24 but which are not used for ratemaking, such as the EPIS
 25 and accumulated amortization associated with retail

1 access software, and electric plant held for future use
2 (which is not includable in rate base in the District of
3 Columbia).

4 As shown on PEPCO (F)-8, page 2, even with the
5 entire \$42,101,000 increase in revenue requested in this
6 proceeding in effect, in 2012 the Company will fall short
7 of earning the ROE required to attract investors as
8 discussed by Company Witness Hevert.

9 Q. DOES THIS CONCLUDE YOUR TESTIMONY?

10 A. Yes, it does.

L. J. HOOK
Direct Exhibit
DC P.S.C. - July, 2011

Introduced as:
PEPCO _____ (F) -1

Potomac Electric Power Company

District of Columbia
Ratemaking Results - Distribution Only
Twelve Months Ending September 30, 2011
(Six Months Actual; Six Months Projected)

(Thousands of Dollars)

Line No.		Average (Unadjusted) (1)	Ratemaking Adjustments (2)	D.C. Adjusted (3)	Revenue to Achieve 10.75% Return on Equity (4)	Adjusted to Reflect 10.75% Return on Equity (5)
Rate Base						
1	Electric Plant in Service	\$ 2,380,818	\$ 13,387	\$ 2,394,205		\$ 2,394,205
2	Accumulated Depreciation	(845,691)	186	(845,505)		(845,505)
3	Accumulated Amortization	(27,677)	19,996	(7,681)		(7,681)
4	Materials and Supplies	20,597	-	20,597		20,597
5	Cash Working Capital	14,333	-	14,333		14,333
6	Accumulated Deferred Income Taxes	(474,502)	(7,336)	(481,838)		(481,838)
7	Prepaid Pension/OPEB Liab. (net of tax)	45,862	3,311	49,173		49,173
8	Customer Deposits	(21,060)	-	(21,060)		(21,060)
9	Pepco Portion of Servco Assets	4,929	1,900	6,829		6,829
10	Regulatory Assets	3,043	34,988	38,031		38,031
11	Unamortized Credit Facility Costs		438	438		438
12	Total Rate Base	\$ 1,100,652	\$ 66,870	\$ 1,167,522		\$ 1,167,522
Operating Revenues						
13	Sale of Electricity	\$ 410,911	\$ -	\$ 410,911		
14	Other Revenues	3,224		3,224		
15	Operating Revenues	\$ 414,135	\$ -	\$ 414,135	\$ 42,101	\$ 456,236
Operating Expenses						
16	Operation and Maintenance	\$ 112,028	\$ (6,891)	\$ 105,137		\$ 105,137
17	Depreciation	59,290	102	59,392		59,392
18	Amortization	3,519	5,779	9,298		9,298
19	Other Taxes	143,743	-	143,743		143,743
20	D.C. Income Tax	2,955	(126)	2,829	\$ 4,200	7,029
21	Federal Income Tax	17,889	(391)	17,498	13,265	30,763
22	Total Operating Expenses	\$ 339,424	\$ (1,527)	\$ 337,897	\$ 17,465	\$ 355,362
23	Operating Income	\$ 74,711	\$ 1,527	\$ 76,238	\$ 24,636	\$ 100,874
24	D.C. Jurisdictional Return on Rate Base	6.79%		6.53%		8.64%
Less Weighted Cost of:						
	Long Term Debt	3.35%		3.35%		3.35%
	Preferred Stock	0.00%		0.00%		0.00%
	Net amount available for common equity	3.44%		3.18%		5.29%
	Common Equity ratio	49.23%		49.23%		49.23%
	D.C. Jurisdictional Return on Equity	6.98%		6.46%		10.75%

Potomac Electric Power Company

District of Columbia Ratemaking Adjustments -- Distribution Only
Twelve Months Ending September 30, 2011
(Six Months Actual, Six Months Projected)

(Thousands of Dollars)

RMA No.	Ratemaking Adjustments	Rate Base (1)	Revenue (2)	Operation & Maintenance (3)	Depreciation (4)	Amortization (5)	Other Taxes (6)	DCIT (7)	FIT (8)
1	Inclusion of projects completed and in service				\$ 69			\$ (7)	\$ (22)
	Electric plant in service	\$ 2,816							
	Accumulated depreciation	(35)							
	Accumulated deferred taxes	(15)							
2	Inclusion of subtransmission plant				229			(23)	(72)
	Electric plant in service	6,427							
	Accumulated depreciation	(120)							
	Accumulated deferred taxes	(554)							
3	Recovery of upgrade to control center EMS	2,224				\$ 490		(49)	(154)
4	Reflection of AMI meters				(48)			5	15
	Electric plant in service	19,103							
	Accumulated depreciation	(996)							
	Accumulated deferred taxes	(6,543)							
5	Reflection of AMI communications equipment & software			\$ 422	63	320		(80)	(254)
	Electric plant in service	2,552							
	Servco assets	1,900							
	Accumulated depreciation	(32)							
	Accumulated amortization	(160)							
	Accumulated deferred taxes	(79)							
6	Recovery of AMI regulatory asset					3,545		(354)	(1,117)
	Regulatory asset, net of accumulated deferred taxes	30,125							
	Accumulated amortization	(1,773)							
7	Reflection of ongoing level of AMI operating costs and savings			(1,025)				102	323
8	Reflection of 2011 pension and OPEB expense	3,311		741				(70)	(235)
9	Recovery of tax on Medicare OPEB tax subsidy					145		(14)	(46)
	Regulatory asset, net of accumulated deferred taxes	209							
10	Removal of F.C. 939 disallowed gainsharing and wages				(34)			3	11
	Electric plant in service	(715)							
	Accumulated depreciation	503							
11	Removal of supplemental executive retirement plans (SERP)			(1,247)	(26)			120	404
	Electric plant in service	(535)							
	Accumulated depreciation	87							
12	Removal of exempt and executive incentive plan costs			(2,051)	(135)			205	693

Potomac Electric Power Company

District of Columbia Ratemaking Adjustments -- Distribution Only
Twelve Months Ending September 30, 2011
(Six Months Actual, Six Months Projected)

(Thousands of Dollars)

RMA No.	Ratemaking Adjustments	Rate Base (1)	Revenue (2)	Operation & Maintenance (3)	Depreciation (4)	Amortization (5)	Other Taxes (6)	DCIT (7)	FIT (8)
	Electric plant in service	(2,845)							
	Accumulated depreciation	261							
13	Annualization of software amortization					(681)		46	222
	Electric plant in service	(22,281)							
	Accumulated amortization	21,929							
14	Removal of 25% of 69 kV lines				(16)			2	5
	Electric plant in service	(635)							
	Accumulated depreciation	635							
15	Reflection of ending amortization - F.C. 1053 rate case costs			(93)				9	29
	Regulatory asset, net of accumulated deferred taxes	(12)							
16	Recovery of F.C. 1076 rate case costs			-				-	-
	Regulatory asset, net of accumulated deferred taxes	(562)							
17	Recovery of F.C. XXXX rate case costs			786				(78)	(248)
	Regulatory asset, net of accumulated deferred taxes	1,150							
18	Recovery of deferred customer education costs					-		-	-
	Regulatory asset, net of accumulated deferred taxes	(582)							
19	Recovery of deferred AMI costs incurred through Dec 31, 2008					-		-	-
	Regulatory asset, net of accumulated deferred taxes	(35)							
20	Reflection of ending amortization - flotation costs					(101)		10	32
	Regulatory asset, net of accumulated deferred taxes	(227)							
21	Inclusion of credit facility costs	438		333				(24)	(108)
22	Annualization of wage increases			927				(88)	(294)
23	Annualization of employee health and welfare costs			379				(36)	(120)
24	Incremental customer care expense			3,273				(310)	(1,037)
25	Reflection of 3-year average regulatory expense			(519)				52	163
26	Reflection of 3-year average storm costs			(765)				76	241
27	Reflection of savings from post CE Divestiture ORP			(818)				78	259
28	Recovery of Organizational Review Project severance costs			(2,998)		1,657		134	422
	Regulatory asset, net of accumulated deferred taxes	2,343							

Potomac Electric Power Company

District of Columbia Ratemaking Adjustments -- Distribution Only
Twelve Months Ending September 30, 2011
(Six Months Actual, Six Months Projected)

(Thousands of Dollars)

RMA No.	Ratemaking Adjustments	Rate Base (1)	Revenue (2)	Operation & Maintenance (3)	Depreciation (4)	Amortization (5)	Other Taxes (6)	DCIT (7)	FIT (8)
29	Reflection of increased fuel costs			150				(14)	(48)
30	Proposed additional vegetation management spend in D.C.			500				(50)	(158)
31	Removal of adjustments to deferred compensation balances			(443)				42	140
32	Removal of employee association costs			(23)				2	7
33	Removal of industry contributions and membership fees			(260)				25	82
34	Removal of institutional advertising/selling expenses			(661)				74	205
35	Removal of Benning environmental liability charge			(3,888)				388	1,225
36	Inclusion of interest expense on customer deposits			48				(5)	(15)
37	Reflection of increased D.C. WASA rates			107				(11)	(34)
38	Reflection of D.C. steel plate fees			234				(23)	(74)
	Electric plant in service	9,500							
	Accumulated depreciation	(117)							
	Accumulated deferred taxes	(145)							
39	Reflection of 2012 Flotation Costs	355				404		(40)	(127)
40	Interest synchronization							(223)	(706)
	Total Ratemaking Adjustments	<u>\$ 66,870</u>	<u>\$ -</u>	<u>\$ (6,891)</u>	<u>\$ 102</u>	<u>\$ 5,779</u>	<u>\$ -</u>	<u>\$ (126)</u>	<u>\$ (391)</u>

POTOMAC ELECTRIC POWER COMPANY

District of Columbia
 Ratemaking Adjustment Calculation
 Twelve Months Ending September 30, 2011
 (Six Months Actual; Six Months Projected)

(Thousands of Dollars)

Line No.	Adjustment 1 - Inclusion of Projects Completed and In-Service	
1	Adjustment to D.C. electric plant in service for items includable under legacy accounting system based on actual data available	<u>\$ 2,816</u>
2	Adjustment to D.C. accumulated depreciation	<u>\$ (35)</u>
3	Adjustment to D.C. accumulated deferred taxes (assuming 20-year tax depreciation)	<u>\$ (15)</u>
4	Adjustment to D.C. depreciation expense	<u>\$ 69</u>
5	Adjustment to D.C. income tax expense	<u>\$ (7)</u>
6	Adjustment to Federal income tax expense	<u>\$ (22)</u>

POTOMAC ELECTRIC POWER COMPANY

District of Columbia
Ratemaking Adjustment Calculation
Twelve Months Ending September 30, 2011
(Six Months Actual; Six Months Projected)

(Thousands of Dollars)

Line No.	Adjustment 2 - Inclusion of Subtransmission Plant			
	Job Descriptions	Balance	Reflected in 13-Mo Avg	Adjustment
1	Addition to Pepco distribution plant (subtransmission)	\$ 16,166		
2	Allocation to D.C. (Subtransmission Plant less AFUDC ratio)	0.4082		
3	Adjustment to D.C. electric plant in service	\$ 6,599	526	\$ 6,073
4	Adjustment to D.C. electric plant in service - AFUDC	368	14	354
5	Total adjustment to D.C. electric plant in service			<u>\$ 6,427</u>
6	Adjustment to D.C. accumulated depreciation	\$ (121)	(1)	<u>\$ (120)</u>
7	Adjustment to D.C. accumulated deferred taxes (assuming 20-year tax depreciation and 50% bonus depr)	\$ (554)	-	<u>\$ (554)</u>
8	Adjustment to D.C. depreciation expense			<u>\$ 229</u>
9	Adjustment to D.C. income tax expense			<u>\$ (23)</u>
10	Adjustment to Federal income tax expense			<u>\$ (72)</u>

POTOMAC ELECTRIC POWER COMPANY

District of Columbia
Ratemaking Adjustment Calculation
Twelve Months Ending September 30, 2011
(Six Months Actual; Six Months Projected)

(Thousands of Dollars)

Line No.	Adjustment 3 - Recovery of Upgrade to Control Center EMS	
1	Upgrade to Control Center EMS	\$ 12,065
2	Allocation to distribution (based on RTU count)	<u>74.3%</u>
3	Distribution-related upgrade to Control Center EMS	8,964
4	Allocation to D.C. (Distribution Plant less AFUDC ratio)	<u>0.4924</u>
5	District of Columbia distribution-related upgrade to Control Center EMS	4,414
6	Annual amortization expense (over life of original lease)	490
7	Amortization expense reflected in twelve months ending September 30, 2011	<u>-</u>
8	Adjustment to D.C. amortization expense	<u>\$ 490</u>
9	Adjustment to D.C. income tax	<u>\$ (49)</u>
10	Adjustment to Federal income tax	<u>\$ (154)</u>
11	Average unamortized balance, net of accumulated deferred tax, at September 30, 2012	<u>\$ 2,224</u>

POTOMAC ELECTRIC POWER COMPANY

District of Columbia
Ratemaking Adjustment Calculation
Twelve Months Ending September 30, 2011
(Six Months Actual; Six Months Projected)

(Thousands of Dollars)

Line No.	Adjustment 4 - Reflection of AMI Meters			
		Full Value	13-month Avg Test Period	Adjustment
1	Adjustment to D.C. electric plant in service for capitalized AMI meters	\$ 27,522	\$ 8,419	\$ 19,103
2	Adjustment to D.C. accumulated depreciation	(1,070) ¹	(74) ²	\$ (996)
3	Adjustment to D.C. accumulated deferred taxes (100% bonus depreciation)	(9,464)	(2,921)	\$ (6,543)
4	Adjustment to D.C. depreciation expense	1,835 ¹	1,883 ^{2, 3}	\$ (48)
5	Adjustment to D.C. income tax expense			\$ 5
6	Adjustment to Federal income tax expense			\$ 15

¹ Based on depreciation of AMI meters over 15-year period.

² Test Period AMI meters depreciated at currently approved non-AMI meter rate until 15-year rate is approved by the Commission.

³ Test Period includes legacy and AMI Meter depreciation expense.

POTOMAC ELECTRIC POWER COMPANY

District of Columbia
Ratemaking Adjustment Calculation
Twelve Months Ending September 30, 2011
(Six Months Actual; Six Months Projected)

(Thousands of Dollars)

Line No.	Adjustment 5 - Reflection of AMI Communication Network and Software	Full Value	13-month Avg Test Period	Adjustment
	<u>Pepco Equipment and Software</u>			
1	Adjustment to EPIS for Communication Network (general plant)	\$ 943	\$ -	\$ 943
2	Adjustment to Depreciation Expense (assuming 15-year life)	63	-	63
3	Adjustment to Accumulated Depreciation	(32)	-	(32)
4	Adjustment to Accumulated Deferred Taxes	(79)	-	(79)
5	Adjustment to EPIS for software/system integration (CBSI)	1,749	140	1,609
6	Adjustment to Amortization Expense (assuming 5-year life)	350	30	320
7	Adjustment to Accumulated Amortization	(175)	(15)	(160)
	<u>PHI Service Company Software</u>			
8	Increase to Pepco-D.C. portion of Servco Assets for Service Company AMI software allocated to Pepco	2,111	- ¹	2,111
9	Adjustment to D.C. O&M expense for amortization charged to Pepco D.C.	422	- ²	422
10	Increase to Pepco-D.C. portion of Servco Assets for accumulated amortization on Service Company AMI software allocated to Pepco	(211)	-	<u>\$ (211)</u>
11	Adjustment to D.C. income tax expense			<u>\$ (80)</u>
12	Adjustment to Federal income tax expense			<u>\$ (254)</u>

¹ AMI-related Service Company software was not included in Servco assets reflected in unadjusted cost of service.

² Amortization of AMI-related Service Company software was not included in unadjusted cost of service.

POTOMAC ELECTRIC POWER COMPANY

District of Columbia
Ratemaking Adjustment Calculation
Twelve Months Ending September 30, 2011
(Six Months Actual; Six Months Projected)

(Thousands of Dollars)

Line No.	Adjustment 6 - Recovery of AMI Regulatory Asset	Regulatory Asset Balance, before CCRF and ADT as of 3/31/2012	Accumulated Capital Cost Recovery Factor as of 3/31/2012	Total Recoverable
1	Loss on early retirement of non-AMI meters	\$ 45,635	\$ 1,289	\$ 46,924
2	Depreciation on non-AMI meters	(932)	(19)	(951)
3	Depreciation on AMI meters	590	10	600
4	Incremental (post-2008) costs	6,412	187	6,599
5	Total regulatory asset to be recovered over 15 years	\$ 51,705	\$ 1,467	\$ 53,172
6	Annual amortization (line 5 ÷ 15 years)			\$ 3,545
7	Balance in regulatory asset after one year (line 5 - line 6)			49,627
8	Adjustment to rate base for average unamortized balance (average of lines 5 & 7)			\$ 51,400
9	Adjustment to rate base for accumulated amortization			\$ (1,773)
10	Adjustment to rate base for accumulated deferred taxes			\$ (21,275)
11	Annual recovery (line 6)			\$ 3,545
12	Actual expense reflected in twelve months ending September 30, 2011			-
13	Adjustment to D.C. amortization expense (line 11 - line 12)			\$ 3,545
14	Adjustment to D.C. income tax			\$ (354)
15	Adjustment to Federal income tax			\$ (1,117)

POTOMAC ELECTRIC POWER COMPANY

District of Columbia
Ratemaking Adjustment Calculation
Twelve Months Ending September 30, 2011
(Six Months Actual; Six Months Projected)

(Thousands of Dollars)

Line No.	Adjustment 7 - Reflection of AMI Ongoing Level of Incremental Costs/Savings	
1	Annualized ongoing level of incremental costs associated with D.C. AMI	\$ 3,050
2	Annualized ongoing level of incremental savings associated with D.C. AMI	<u>4,075</u> ¹
3	Adjustment to D.C. O & M expense	<u>\$ (1,025)</u>
4	Adjustment to D.C. income tax	<u>\$ 102</u>
5	Adjustment to Federal income tax	<u>\$ 323</u>

¹ Assumes remote disconnect/reconnect capability.

POTOMAC ELECTRIC POWER COMPANY

District of Columbia
Ratemaking Adjustment Calculation
Twelve Months Ending September 30, 2011
(Six Months Actual; Six Months Projected)

(Thousands of Dollars)

Line No.	Adjustment 8 - Reflection of 2011 Pension and OPEB Expense	Pension	OPEB	Total
1	Average net-of-tax prepaid pension and OPEB balance - Pepco - at 12/31/2011	\$ 159,375	\$ (36,316)	\$ 123,059
2	Average net-of-tax prepaid pension and OPEB balance - Pepco - at 9/30/2011	158,481	(37,441)	121,040
3	Adjustment to Pepco net of tax prepaid pension and OPEB assets	\$ 894	\$ 1,125	2,019
4	Adjustment to include Pepco portion of Service Company net of tax prepaid pension/OPEB	\$ 14,700	\$ (7,980)	6,720
5	Allocation to D.C. (O&M less A&G ratio)			0.3789
6	Adjustment to D.C. net-of-tax prepaid pension and OPEB (line 5 * {line 3 + line 4})			\$ 3,311
7	2011 Pepco pension and OPEB expense includable in distribution-related O&M	\$ 11,661	\$ 7,787	\$ 19,448
8	2011 Service Company pension and OPEB expense chargeable to Pepco distribution-related O&M	4,870	5,021	9,891
9	Total 2011 pension and OPEB expense in Pepco distribution-related O&M	\$ 16,531	\$ 12,808	\$ 29,339
10	Pepco pension and OPEB expense included in distribution-related O&M for the twelve months ending September 30, 2011	\$ 10,758	\$ 7,786	\$ 18,544
11	Service Company pension and OPEB expense charged to Pepco distribution-related O&M for the twelve months ending September 30, 2011	6,607	2,232	8,839
12	Total pension and OPEB expense included in distribution-related O&M for the 12-months ending September 30, 2011	\$ 17,365	\$ 10,018	\$ 27,383
13	Adjustment to Pepco distribution-related O&M pension and OPEB expense	\$ (834)	\$ 2,790	\$ 1,956
14	Allocation to D.C. (O&M less A&G ratio)			0.3789
15	Adjustment to D.C. operations and maintenance expense			\$ 741
16	Adjustment to D.C. income tax expense			\$ (70)
17	Adjustment to Federal income tax expense			\$ (235)

POTOMAC ELECTRIC POWER COMPANY

District of Columbia
Ratemaking Adjustment Calculation
Twelve Months Ending September 30, 2011
(Six Months Actual; Six Months Projected)

(Thousands of Dollars)

Line No.	Adjustment 9 - Recovery of Tax on OPEB Medicare Tax Subsidy	Balance	ADT	Net
1	Tax on total Pepco OPEB Medicare tax subsidy	\$ 1,275		\$ 1,275
2	Allocation to Distribution (Labor ratio)	0.8985		0.8985
3	Distribution-related portion	1,146		1,146
4	Allocation to D.C. (O&M less A&G ratio)	0.3789		0.3789
5	Total D.C. allocated distribution-related portion	434	(183)	251
6	Annual recovery (line 5 + 3 years)	145		145
7	Balance after one year	289	(122)	167
8	Average addition to rate base, net of deferred taxes			\$ 209
9	Actual expense reflected in twelve months ending September 30, 2011			-
10	Adjustment to D.C. amortization expense (line 6 - line 9)			\$ 145
11	Adjustment to D.C. income tax			\$ (14)
12	Adjustment to Federal income tax			\$ (46)

POTOMAC ELECTRIC POWER COMPANY

District of Columbia
Ratemaking Adjustment Calculation
Twelve Months Ending September 30, 2011
(Six Months Actual; Six Months Projected)

(Thousands of Dollars)

Line No.	Adjustment 10 - Removal of Capitalized Portion of Disallowed Corporate Gainsharing and Wages in Formal Case No. 939	
1	Capitalized portion of Corporate Gainsharing (& associated FICA) included in 13-month average unadjusted electric plant in service	\$ 1,539
2	Capitalized portion of 1994 and 1995 exempt wage increases in excess of 3% included in 13-month average unadjusted electric plant in service	171
3	Total capitalized expense included in electric plant in service	1,710
4	Allocation to Distribution (Plant less AFUDC ratio)	0.8491
5	Distribution related capitalized expense included in electric plant in service	1,452
6	Allocation to D.C. (Plant less AFUDC ratio)	0.4924
7	Adjustment to D.C. electric plant in service	\$ (715)
8	Accumulated depreciation included in 13 month average unadjusted results	\$ (1,286)
9	Allocation to Distribution (Depreciation less AFUDC ratio)	0.8594
10	Distribution related accumulated depreciation	(1,105)
11	Allocation to D.C. (Accumulated Depreciation less AFUDC ratio)	0.3911
12	Adjustment to D.C. accumulated depreciation	\$ 503
13	Depreciation expense included in unadjusted results for twelve months ending September 30, 2011	\$ 85
14	Allocation to Distribution (Depreciation less AFUDC ratio)	0.8594
15	Distribution related depreciation expense	73
16	Allocation to D.C. (Depreciation less AFUDC ratio)	0.4667
17	Adjustment to D.C. depreciation expense	\$ (34)
18	Adjustment to D.C. income tax expense	\$ 3
19	Adjustment to Federal income tax expense	\$ 11

POTOMAC ELECTRIC POWER COMPANY

District of Columbia
Ratemaking Adjustment Calculation
Twelve Months Ending September 30, 2011
(Six Months Actual; Six Months Projected)

(Thousands of Dollars)

Line No.	Adjustment 11 - Removal of Non-Qualified Supplemental Executive Retirement Plans	
1	13 month average capitalized Pepco utility Non-Qualified Plan expense	\$ 810
2	13 month average capitalized Service Company Non-Qualified Plan expense charged to Pepco	469
3	Total 13 month average capitalized Non-Qualified Plan expense	1,279
4	Allocation to Distribution (Plant less AFUDC ratio)	0.8491
5	Distribution related capitalized Non-Qualified Plan expense	1,086
6	Allocation to D.C. (Plant less AFUDC ratio)	0.4924
7	Adjustment to D.C. electric plant in service	<u>\$ (535)</u>
8	13 month average accumulated depreciation	\$ (259)
9	Allocation to Distribution (Depreciation less AFUDC ratio)	0.8594
10	Distribution related portion of 13 month average accumulated depreciation	(223)
11	Allocation to D.C. (Accumulated Depreciation less AFUDC ratio)	0.3911
12	Adjustment to D.C. accumulated depreciation	<u>\$ 87</u>
13	Depreciation expense	\$ 64
14	Allocation to Distribution (Depreciation less AFUDC ratio)	0.8594
15	Distribution related portion of depreciation expense	55
16	Allocation to D.C. (Depreciation less AFUDC ratio)	0.4667
17	Adjustment to D.C. depreciation expense	<u>\$ (26)</u>
18	Pepco utility Non-Qualified Plan expense for the twelve months ending September 30, 2011	\$ 1,662
19	Service Co. Non-Qualified Plan charged to Pepco for the twelve months ending September 30, 2011	2,000
20	Total Non-Qualified Plan O&M expense for the twelve months ending September 30, 2011	3,662
21	Allocation to Distribution (Labor ratio)	0.8985
22	Distribution-related operation & maintenance expense	3,290
23	Allocation to D.C. (O&M less A&G ratio)	0.3789
24	Adjustment to D.C. operations & maintenance expense	<u>\$ (1,247)</u>
25	Adjustment to D.C. income tax expense	<u>\$ 120</u>
26	Adjustment to Federal income tax expense	<u>\$ 404</u>

POTOMAC ELECTRIC POWER COMPANY

District of Columbia
Ratemaking Adjustment Calculation
Twelve Months Ending September 30, 2011
(Six Months Actual; Six Months Projected)

(Thousands of Dollars)

Line No.	Adjustment 12 - Removal of Exempt and Executive Incentive Plans	
1	Average capitalized incentive costs in electric plant in service (EPIS)	\$ 6,805
2	Allocation to Distribution (Plant less AFUDC ratio)	<u>0.8491</u>
3	Average distribution related capitalized incentive costs in EPIS	5,778
4	Allocation to D.C. (Plant less AFUDC ratio)	<u>0.4924</u>
5	Adjustment to remove average capitalized incentive costs from D.C. EPIS	<u>\$ (2,845)</u>
6	Average capitalized incentive costs in accumulated depreciation	\$ (777)
7	Allocation to Distribution (Depreciation less AFUDC ratio)	<u>0.8594</u>
8	Average distribution related capitalized incentive costs in accumulated depreciation	(668)
9	Allocation to D.C. (Accumulated depreciation less AFUDC ratio)	<u>0.3911</u>
10	Adjustment to remove average capitalized incentive costs from D.C. accumulated depreciation	<u>\$ 261</u>
11	Average capitalized incentive costs in depreciation expense	\$ 338
12	Allocation to Distribution (Depreciation less AFUDC ratio)	<u>0.8594</u>
13	Average distribution related capitalized incentive costs in depreciation expense	290
14	Allocation to D.C. (Depreciation less AFUDC ratio)	<u>0.4667</u>
15	Adjustment to remove average capitalized incentive costs from D.C. depreciation expense	<u>\$ (135)</u>
16	Distribution-related incentive costs charged to Pepco utility O&M for the twelve months ending September 30, 2011	\$ 498
17	Distribution-related Service Co. incentive costs charged to Pepco utility O&M for the twelve months ending September 30, 2011	<u>4,916</u>
18	Distribution-related incentive costs in Pepco O&M expense	5,414
19	Allocation to D.C. (O&M less A&G ratio)	<u>0.3789</u>
20	Adjustment to D.C. operations and maintenance expense to remove incentive costs	<u>\$ (2,051)</u>
21	Adjustment to D.C. income tax expense	<u>\$ 205</u>
22	Adjustment to Federal income tax expense	<u>\$ 693</u>

POTOMAC ELECTRIC POWER COMPANY

District of Columbia
Ratemaking Adjustment Calculation
Twelve Months Ending September 30, 2011
(Six Months Actual; Six Months Projected)

(Thousands of Dollars)

Line No.	Adjustment 13 - Annualization of Software Amortization	Non-AFUDC	DC AFUDC	Total
	ADJUSTMENTS TO RATE BASE			
1	13-month average EPIS included in test period of software projects ending within one year	\$ 45,185	\$ 2,483	\$ 47,668
2	Annualization of EPIS for new software projects capitalized	(134)	-	(134)
3	Change in average EPIS	(45,319)	(2,483)	(47,802)
4	Allocation to Distribution (Labor ratio)	0.8985	0.8985	
5	Change in distribution-related average EPIS	(40,719)	(2,231)	(42,950)
6	Allocation to D.C. (Distribution Plant less AFUDC ratio)	0.4924	1.0000	
7	Adjustment to D.C. electric plant in service	\$ (20,050)	\$ (2,231)	\$ (22,281)
8	13-month average accumulated amortization included in test period for software projects ending within one year	\$ (44,563)	\$ (2,453)	\$ (47,016)
9	Annualization of accumulated amortization for new software projects capitalized	21	-	21
10	Change in average accumulated amortization	44,584	2,453	47,037
11	Allocation to Distribution (Labor ratio)	0.8985	0.8985	
12	Change in distribution-related average accumulated amortization	40,059	2,204	42,263
13	Allocation to D.C. (Distribution Plant less AFUDC ratio)	0.4924	1.0000	
14	Adjustment to D.C. accumulated amortization	\$ 19,725	\$ 2,204	\$ 21,929
	ANNUALIZATION OF AMORTIZATION EXPENSE			
15	Amortization expense included in test period for software projects ending by September 30, 2011	\$ 1,307	\$ 102	\$ 1,409
16	Additional (annualized) expense for new projects capitalized	(24)	-	(24)
17	Adjustment to amortization expense	(1,331)	(102)	(1,433)
18	Allocation to Distribution (Labor ratio)	0.8985	0.8985	
19	Distribution-related adjustment to amortization expense	(1,196)	(92)	(1,288)
20	Allocation to D.C. (Distribution Plant less AFUDC ratio)	0.4924	1.0000	
21	Adjustment to D.C. amortization expense	\$ (589)	\$ (92)	\$ (681)
22	Adjustment to D.C. income tax expense			\$ 46
23	Adjustment to Federal income tax expense			\$ 222

POTOMAC ELECTRIC POWER COMPANY

District of Columbia
Ratemaking Adjustment Calculation
Twelve Months Ending September 30, 2011
(Six Months Actual; Six Months Projected)

(Thousands of Dollars)

Line No.	Adjustment 14 - Removal of 25% of 69 kV Lines (F.C. 1076)	
1	Balance reflected in electric plant in service	\$ 2,540
2	Approximate percentage removed from service	<u>25%</u>
3	Adjustment to EPIS to exclude 25% of 69 kV lines removed from service	<u>\$ (635)</u>
4	Adjustment to D.C. accumulated depreciation	<u>\$ 635</u>
5	Adjustment to D.C. depreciation expense	<u>\$ (16)</u>
6	Adjustment to D.C. income tax expense	<u>\$ 2</u>
7	Adjustment to Federal income tax expense	<u>\$ 5</u>

POTOMAC ELECTRIC POWER COMPANY

District of Columbia
Ratemaking Adjustment Calculation
Twelve Months Ending September 30, 2011
(Six Months Actual; Six Months Projected)

(Thousands of Dollars)

Line No.	Adjustment 15 - Reflection of Ending Amortization - F.C. 1053 Rate Case Costs	
1	Amortization expense in rate effective period	\$ -
2	Amortization expense included in test period	<u>93</u>
3	Adjustment to D.C. operation and maintenance expense	<u>\$ (93)</u>
4	Adjustment to D.C. income tax	<u>\$ 9</u>
5	Adjustment to Federal income tax	<u>\$ 29</u>
6	Average unamortized rate case costs, net of accumulated deferred tax, at September 30, 2012	\$ -
7	Average unamortized rate case costs, net of accumulated deferred tax, at September 30, 2011	<u>12</u>
8	Adjustment to regulatory asset	<u>\$ (12)</u>

POTOMAC ELECTRIC POWER COMPANY

District of Columbia
Ratemaking Adjustment Calculation
Twelve Months Ending September 30, 2011
(Six Months Actual; Six Months Projected)

(Thousands of Dollars)

Line No.	Adjustment 16 - Recovery of F.C. 1076 Rate Case Costs	
1	Total rate case costs deferred and amortized over a three-year period	\$ 2,880
2	Annual recovery (Line 1 ÷ 3 years)	960
3	Actual expense reflected in twelve months ending September 30, 2011	<u>960</u>
4	Adjustment to D.C. operations and maintenance expense	<u>\$ -</u>
5	Adjustment to D.C. income tax	<u>\$ -</u>
6	Adjustment to Federal income tax	<u>\$ -</u>
7	Average unamortized rate case costs, net of accumulated deferred tax, at September 30, 2012	\$ 515
8	Average unamortized rate case costs, net of accumulated deferred tax, at September 30, 2011	<u>1,077</u>
9	Adjustment to regulatory asset	<u>\$ (562)</u>

POTOMAC ELECTRIC POWER COMPANY

District of Columbia
Ratemaking Adjustment Calculation
Twelve Months Ending September 30, 2011
(Six Months Actual; Six Months Projected)

(Thousands of Dollars)

Line No.	Adjustment 17 - Recovery of F.C. XXXX Rate Case Costs	
1	Total rate case costs to be deferred and amortized over a three-year period	\$ 2,358
2	Annual recovery (Line 1 ÷ 3 years)	786
3	Actual expense reflected in twelve months ending September 30, 2011	-
4	Adjustment to D.C. operations and maintenance expense	<u>\$ 786</u>
5	Adjustment to D.C. income tax	<u>\$ (78)</u>
6	Adjustment to Federal income tax	<u>\$ (248)</u>
7	Average unamortized rate case costs, net of accumulated deferred tax, at September 30, 2012	<u>\$ 1,150</u>

POTOMAC ELECTRIC POWER COMPANY

District of Columbia
Ratemaking Adjustment Calculation
Twelve Months Ending September 30, 2011
(Six Months Actual; Six Months Projected)

(Thousands of Dollars)

Line No.	Adjustment 18 - Recovery of Deferred Customer Education Costs (F.C. 1076)	
1	Total D.C. customer education costs deferred and amortized over a three-year period	\$ 2,980
2	Annual recovery (line 1 ÷ 3 years)	993
3	Actual expense reflected in twelve months ending September 30, 2011	<u>993</u>
4	Adjustment to D.C. amortization expense	<u>\$ -</u>
5	Adjustment to D.C. income tax	<u>\$ -</u>
6	Adjustment to Federal income tax	<u>\$ -</u>
7	Average unamortized deferred customer education costs, net of accumulated deferred tax, at September 30, 2012	\$ 581
8	Average unamortized deferred customer education costs, net of accumulated deferred tax, at September 30, 2011	<u>1,163</u>
9	Adjustment to regulatory asset, net of accumulated deferred tax	<u>\$ (582)</u>

POTOMAC ELECTRIC POWER COMPANY

District of Columbia
Ratemaking Adjustment Calculation
Twelve Months Ending September 30, 2011
(Six Months Actual; Six Months Projected)

(Thousands of Dollars)

Line No.	Adjustment 19 - Recovery of Deferred AMI Costs Incurred through December 31, 2008	
1	Deferred D.C. AMI costs (incurred through December 31, 2008) approved for recoverable in Formal Case No. 1076	\$ 911
2	Annual recovery (line 1 ÷ 15 years)	\$ 61
3	Actual expense reflected in twelve months ending September 30, 2011	<u>61</u>
4	Adjustment to D.C. amortization expense	<u>\$ -</u>
5	Adjustment to D.C. income tax	<u>\$ -</u>
6	Adjustment to Federal income tax	<u>\$ -</u>
7	Average unamortized AMI costs, net of accumulated deferred tax, at September 30, 2012	\$ 462
8	Average unamortized AMI costs, net of accumulated deferred tax, at September 30, 2011	<u>497</u>
9	Adjustment to regulatory asset, net of accumulated deferred tax	<u>\$ (35)</u>

POTOMAC ELECTRIC POWER COMPANY

District of Columbia
Ratemaking Adjustment Calculation
Twelve Months Ending September 30, 2011
(Six Months Actual; Six Months Projected)

(Thousands of Dollars)

Line No.	Adjustment 20 - Reflection of Ending Amortization - Flotation Costs for Common Stock Issuance	
1	Amortization expense in rate effective period	\$ 303
2	Amortization expense included in test period	<u>404</u>
3	Adjustment to D.C. amortization expense	<u>\$ (101)</u>
4	Adjustment to D.C. income tax	<u>\$ 10</u>
5	Adjustment to Federal income tax	<u>\$ 32</u>
6	Average unamortized flotation costs, net of accumulated deferred tax, at 9/30/2012	\$ 68
7	Average unamortized flotation costs, net of accumulated deferred tax, at 9/30/2011	<u>295</u>
8	Adjustment to regulatory asset, net of accumulated deferred tax	<u>\$ (227)</u>

POTOMAC ELECTRIC POWER COMPANY

District of Columbia
Ratemaking Adjustment Calculation
Twelve Months Ending September 30, 2011
(Six Months Actual; Six Months Projected)

(Thousands of Dollars)

Line No.	Adjustment 21 - Inclusion of Credit Facility Costs	
1	13-month average unamortized balance of start-up costs	\$ 1,047
2	Allocation to Distribution (Plant less AFUDC ratio)	<u>0.8491</u>
3	Adjustment to D.C. distribution plant	889
4	Allocation to D.C. (Plant less AFUDC ratio)	<u>0.4924</u>
5	Addition to D.C. rate base	<u><u>\$ 438</u></u>
6	Annual amortization of start-up costs	\$ 289
7	Annual cost of maintaining credit facility	<u>507</u>
8	Total expense	796
9	Allocation to Distribution (Plant less AFUDC ratio)	<u>0.8491</u>
10	Adjustment to Distribution-related expense	676
11	Allocation to D.C. (Plant less AFUDC ratio)	<u>0.4924</u>
12	Adjustment to D.C. operations & maintenance expense	<u><u>\$ 333</u></u>
13	Adjustment to D.C. income tax expense	<u><u>\$ (24)</u></u>
14	Adjustment to Federal income tax expense	<u><u>\$ (108)</u></u>

POTOMAC ELECTRIC POWER COMPANY

District of Columbia
Ratemaking Adjustment Calculation
Twelve Months Ending September 30, 2011
(Six Months Actual; Six Months Projected)

(Thousands of Dollars)

Line No.	Adjustment 22 - Annualization of Wage Increases	Mgmt	Union	Total
<u>ANNUALIZATION OF TEST PERIOD INCREASES (3/1/11 MGMT, 6/1/11 UNION)</u>				
	Distribution-related O&M wages/overtime, excluding one-time payments, before 3/1/11 for Management and before 6/1/11 for Union employees:			
1	Pepco	\$ 6,160	\$ 30,100	
2	Less: Incremental wages/overtime related to January 2011 storm	(262)	(1,028)	
3	Less: Incremental wages/overtime related to Summer 2010 storms	-	-	
4	Net amount	5,898	29,072	
5	Charged to Pepco from Service Company	14,179	3,733	
6	Less: Incremental wages/overtime related to January 2011 storm	(181)	(29)	
7	Less: Incremental wages/overtime related to Summer 2010 storms	(10)	-	
8	Net amount	13,988	3,704	
9	Test period percentage wage increase	3.01%	2.00%	
	Adjustment to annualize wage increases occurring in test period:			
10	Pepco (line 4 * line 9)	178	581	
11	Charged to Pepco from Service Company (line 8 * line 9)	421	74	
12	Total adjustment to annualize wage increases in test period	599	655	
<u>ADJUSTMENT TO REFLECT INCREASES WITHIN 12 MOS. OF TEST PERIOD</u>				
13	Actual test year wages (distribution-related O&M) - Pepco	14,344	44,995	
14	Plus annualization (line 10)	178	581	
15	Less incremental storm-related labor (lines 2 and 3)	(262)	(1,028)	
16	Net amount	14,260	44,548	
17	Actual test year wages (distribution-related O&M) charged to Pepco from service co.	33,183	5,328	
18	Plus annualization (line 11)	421	74	
19	Less incremental storm-related labor (lines 6 and 7)	(191)	(29)	
20	Net amount	33,413	5,373	
21	Increase percent	3%	2%	
22	No. of months applicable	7	4	
	Adjustment to annualize wage increases occurring in test period:			
23	Pepco (line 16 * line 21 * line 22 + 12)	250	297	
24	Charged to Pepco from service co. (line 20 * line 21 * line 22 + 12)	585	36	
25	Total adjustment	835	333	
<u>ADJUSTMENT TO REFLECT END OF PERIOD HEADCOUNT PER F.C. 1053</u>				
26	Annualized wages, net of incremental storm labor - Pepco (line 10 + line 23)	428	878	
	Employee Count-Pepco			
27	Average number of Pepco employees during test period (based on actual and budget)	342	1,043	
28	Number of Pepco employees as of 9/30/11	369	1,071	
29	% end-of-period to average workforce level	107.89%	102.68%	
30	Adjustment ((line 26 * line 29)-line 26)	34	24	
31	Annualized wages, net of incremental storm labor charged to Pepco (line 11 + line 24)	1,006	110	
	Employee Count-Service company			
32	Avg no. of Service co employees during test period (based on actual and budget)	1,284	342	
33	Number of Service co employees as of 9/30/11	1,244	336	
34	% end-of-period to average workforce level	96.88%	98.25%	
35	Adjustment ((line 31 * line 34)- line 31)	(31)	(2)	
	Total adjustment to wages:			
36	Pepco (line 10 + line 23 + line 30)	462	902	
37	Charged to Pepco from Service Company (line 11 + line 31 + line 35)	975	108	
38	Total adjustment	1,437	1,010	\$ 2,447
39	Allocation to D.C. (O&M less A&G ratio)	0.3789	0.3789	0.3789
40	Adjustment to D.C. Operations & Maintenance for wage increases	\$ 544	\$ 383	\$ 927
41	Adjustment to D.C. income tax expense			\$ (88)
42	Adjustment to Federal income tax expense			\$ (294)

POTOMAC ELECTRIC POWER COMPANY

District of Columbia
Ratemaking Adjustment Calculation
Twelve Months Ending September 30, 2011
(Six Months Actual; Six Months Projected)

(Thousands of Dollars)

Line No.	Plan	Test Period Amount	Rate Effective Period	Projected Change
Adjustment 23 - Annualization of Employee Health & Welfare Costs				
1	Medical	\$ 12,979	\$ 14,017	\$ 1,038
2	Dental	1,097	1,152	55
3	Vision	395	415	20
4	Total change in health & welfare costs included in O&M expense			1,113
5	Allocation to distribution (Labor Ratio)			0.8985
6	Distribution-related adjustment to health & welfare costs			1,000
7	Allocation factor - DC O&M less A&G			0.3789
8	Adjustment to DC operations and maintenance expense			\$ 379
9	Adjustment to DC income tax expense			\$ (36)
10	Adjustment to Federal income tax expense			\$ (120)

POTOMAC ELECTRIC POWER COMPANY

District of Columbia
Ratemaking Adjustment Calculation
Twelve Months Ending September 30, 2011
(Six Months Actual; Six Months Projected)

(Thousands of Dollars)

Line No.	Adjustment 24 - Annualization of Incremental Customer Care Expense	Reflected in		
		Total Additional Expenditures	Actual Months of Test Year	Adjustment
	Incremental customer care expense:			
1	Personnel	\$ 4,971	\$ 112	\$ 4,859
2	Infrastructure (hardware and software)	1,080	-	1,080
3	Storm preparedness	2,000	500	1,500
4	Customer education and research	1,200	-	1,200
5	Total annual recurring incremental expense			\$ 8,639
6	Allocation to D.C. (O&M less A&G ratio)			0.3789
7	Adjustment to D.C. operations and maintenance expense			\$ 3,273
8	Adjustment to D.C. income tax			\$ (310)
9	Adjustment to Federal income tax			\$ (1,037)

POTOMAC ELECTRIC POWER COMPANY

District of Columbia
Ratemaking Adjustment Calculation
Twelve Months Ending September 30, 2011
(Six Months Actual; Six Months Projected)

(Thousands of Dollars)

Line No.	Adjustment 25 - Reflection of 3-Year Average Non-Deferred Regulatory Costs	
		<u>D.C. Direct</u>
1	9/30/2009 regulatory expense (excludes F.C. 1076 deferred costs)	\$ 1,350
2	9/30/2010 regulatory expense (excludes F.C. 1076 deferred costs)	1,775
3	9/30/2011 regulatory expense	<u>2,341</u>
4	D.C. 3-year total	<u>\$ 5,466</u>
5	Three-year average D.C. regulatory expense	\$ 1,822
6	D.C. regulatory expense for the twelve months ending September 30, 2011	<u>2,341</u>
7	Adjustment to D.C. operations & maintenance expense	<u>\$ (519)</u>
8	Adjustment to D.C. income tax expense	<u>\$ 52</u>
9	Adjustment to Federal income tax expense	<u>\$ 163</u>

POTOMAC ELECTRIC POWER COMPANY

District of Columbia
Ratemaking Adjustment Calculation
Twelve Months Ending September 30, 2011
(Six Months Actual; Six Months Projected)

(Thousands of Dollars)

Line No.	Adjustment 26 - Reflection of 3-Year Average Storm Costs	System	Allocator	D.C.
	Storm restoration costs reflected in distribution related O&M expense:			
1	Twelve months ending September 30, 2009	\$ 2,443	0.3789	\$ 926
	Twelve months ending September 30, 2010			
	Directly assigned based on restorations			
2	February 2010 - Snow event incremental costs	7,083	0.0800	567
3	July 25, 2010 - Storm event incremental costs	6,285	0.1100	691
4	August 5, 2010 - Storm event incremental costs	651	0.0500	33
5	August 12, 2010 - Storm event incremental costs	3,067	0.1600	491
6	Allocable	6,223	0.3789	2,358
7	Total for twelve months ending September 30, 2010	<u>\$ 23,309</u>		<u>\$ 4,140</u>
	Twelve months ending September 30, 2011			
	Directly assigned based on restorations			
8	January 2011 - Snow event incremental costs	10,333	0.0800	827
9	Allocable	7,533	0.3789	2,854
10	Total for twelve months ending September 30, 2011	<u>\$ 17,866</u>		<u>\$ 3,681</u>
11	Three-year average storm costs - D.C.			\$ 2,916
12	Adjustment to D.C. O&M expense to reflect 3-year average storm damage costs (Line 11 - Line 10)			<u>\$ (765)</u>
13	Adjustment to D.C. income tax expense			<u>\$ 76</u>
14	Adjustment to Federal income tax expense			<u>\$ 241</u>

POTOMAC ELECTRIC POWER COMPANY

District of Columbia
Ratemaking Adjustment Calculation
Twelve Months Ending September 30, 2011
(Six Months Actual; Six Months Projected)

(Thousands of Dollars)

Line No.	Adjustment 27 - Reflection of Savings from Organizational Review Project post-Conectiv Energy Divestiture	
	Estimated annual savings resulting from Organizational Review post-Conectiv Energy Divestiture:	
1	Labor-related savings	\$ 25,956
2	Non-Labor-related savings (Insurance, consulting, information technology)	1,860
3	Total annual PHI Corporate Center and Support Services savings	<u>\$ 27,816</u>
4	Percent of Corporate Center/Support Services charged to Pepco Power Delivery O&M	<u>34.55%</u>
5	Annual savings - Pepco Power Delivery O&M	9,610
6	Allocation to Distribution (Labor Ratio)	<u>0.8985</u>
7	Annual savings - distribution-related O&M	8,635
8	Adjustment to reflect distribution-related savings not included in Quarter 4, 2010 actuals (line 7 ÷ 4)	(2,159)
9	Allocation to D.C. (O&M less A&G ratio)	<u>0.3789</u>
10	Adjustment to D.C. allocated O&M expense	<u>\$ (818)</u>
11	Adjustment to D.C. income tax expense	<u>\$ 78</u>
12	Adjustment to Federal income tax expense	<u>\$ 259</u>

POTOMAC ELECTRIC POWER COMPANY

District of Columbia
Ratemaking Adjustment Calculation
Twelve Months Ending September 30, 2011
(Six Months Actual; Six Months Projected)

(Thousands of Dollars)

Line No.	Adjustment 28 - Recovery of Organizational Review Project Severance	
1	Total distribution related severance costs included in the twelve months ending September 30, 2011	\$ 7,912
2	Allocation to D.C. (O&M less A&G ratio)	<u>0.3789</u>
3	Adjustment to remove D.C. allocated severance costs in O&M expense	<u>\$ (2,998)</u>
4	D.C. allocated severance costs to be deferred and amortized over a three-year period	\$ 4,971
5	Annual recovery of D.C. allocated deferred severance costs (line 4 ÷ 3 years)	1,657
6	Actual amortization expense reflected in twelve months ending September 30, 2011	<u>-</u>
7	Adjustment to D.C. amortization expense	<u>\$ 1,657</u>
8	Adjustment to D.C. income tax	<u>\$ 134</u>
9	Adjustment to Federal income tax	<u>\$ 422</u>
10	Average unamortized deferred severance costs, net of accumulated deferred tax, at September 30, 2012	<u>\$ 2,343</u>

POTOMAC ELECTRIC POWER COMPANY

District of Columbia
Ratemaking Adjustment Calculation
Twelve Months Ending September 30, 2011
(Six Months Actual; Six Months Projected)

(Thousands of Dollars)

Line No.	Adjustment 29 - Reflection of Increased Fuel Costs			
		Bio-diesel Blend	Regular Unleaded	Total
1	Fuel costs reflected in twelve months ending September 30, 2011	\$ 1,159	\$ 780	\$ 1,939
2	Usage in gallons	372.1	263.3	
3	Average price per gallon	\$ 3.11	\$ 2.96	
4	Average price per gallon in rate effective period (based on May actual)	\$ 3.71	\$ 3.80	
5	Fuel costs based on test period usage and current fuel prices	\$ 1,380	\$ 1,001	\$ 2,381
6	Increase in operations and maintenance expense due to rising fuel costs			\$ 442
7	Allocation to Distribution (Labor Ratio)			<u>0.8985</u>
8	Increase in distribution operations and maintenance expense			397
9	Allocation to D.C. (O&M less A&G ratio)			<u>0.3789</u>
10	Adjustment to D.C. distribution-related O&M expense			<u>\$ 150</u>
11	Adjustment to D.C. income tax			<u>\$ (14)</u>
12	Adjustment to Federal income tax			<u>\$ (48)</u>

POTOMAC ELECTRIC POWER COMPANY

District of Columbia
Ratemaking Adjustment Calculation
Twelve Months Ending September 30, 2011
(Six Months Actual; Six Months Projected)

(Thousands of Dollars)

Line

No. Adjustment 30 - Proposed Additional Vegetation Management Activity - D.C.

1	Incremental costs associated with proposed additional vegetation management in D.C.	<u>\$</u>	<u>500</u>
2	Adjustment to D.C. income tax	<u>\$</u>	<u>(50)</u>
3	Adjustment to Federal income tax	<u>\$</u>	<u>(158)</u>

POTOMAC ELECTRIC POWER COMPANY

District of Columbia
Ratemaking Adjustment Calculation
Twelve Months Ending September 30, 2011
(Six Months Actual; Six Months Projected)

(Thousands of Dollars)

Line No.	Adjustment 31 - Removal of Adjustments to Deferred Compensation Balances	
1	Impact of adjustments to deferred compensation liability on O&M expense	\$ 1,301
2	Allocation to Distribution (Labor ratio)	<u>0.8985</u>
3	Distribution related impact of adjustments to deferred compensation liability on O&M expense	1,169
4	Allocation to D.C. (O&M less A&G ratio)	<u>0.3789</u>
5	Adjustment to D.C. operations and maintenance expense	<u>\$ (443)</u>
6	Adjustment to D.C. income tax expense	<u>\$ 42</u>
7	Adjustment to Federal income tax expense	<u>\$ 140</u>

POTOMAC ELECTRIC POWER COMPANY

District of Columbia
Ratemaking Adjustment Calculation
Twelve Months Ending September 30, 2011
(Six Months Actual; Six Months Projected)

(Thousands of Dollars)

Line No.	Adjustment 32 - Removal of Employee Association Costs	
1	Total employee association costs to be excluded per Formal Case 1076	\$ 68
2	Allocation to Distribution (Labor Ratio)	<u>0.8985</u>
3	Excludable employee association costs included in distribution O&M	<u>\$ 61</u>
4	Allocation to D.C. (O&M less A&G ratio)	<u>0.3789</u>
5	Adjustment to D.C. operations and maintenance expense	<u>\$ (23)</u>
6	Adjustment to D.C. income tax expense	<u>\$ 2</u>
7	Adjustment to Federal income tax expense	<u>\$ 7</u>

POTOMAC ELECTRIC POWER COMPANY

District of Columbia
Ratemaking Adjustment Calculation
Twelve Months Ending September 30, 2011
(Six Months Actual; Six Months Projected)

(Thousands of Dollars)

Line No.	Adjustment 33 - Removal of Industry Contributions and Membership Fees	
1	Industry contributions and membership fees for the twelve months ending 9/30/2011	\$ 763
2	Fees and contributions allowable per Order Nos. 9509 and 1053: American National Standards Institute	<u>1</u>
3	Total industry contributions and membership fees to be excluded	762
4	Allocation to Distribution (Labor Ratio)	<u>0.8985</u>
5	Excludable industry contributions & membership fees included in distribution O&M	685
6	Allocation to D.C. (O&M less A&G ratio)	<u>0.3789</u>
7	Adjustment to D.C. operations and maintenance expense	<u>\$ (260)</u>
8	Adjustment to D.C. income tax expense	<u>\$ 25</u>
9	Adjustment to Federal income tax expense	<u>\$ 82</u>

POTOMAC ELECTRIC POWER COMPANY

District of Columbia
Ratemaking Adjustment Calculation
Twelve Months Ending September 30, 2011
(Six Months Actual; Six Months Projected)

(Thousands of Dollars)

Line No.	Adjustment 34 - Removal of Institutional Advertising and Selling Expense	
1	Total advertising/selling expenses (FERC accounts 909, 911, 912, 913, 930.1) for the twelve months ending September 30, 2011	\$ 2,389
2	Expenses included above associated with informational activity	<u>336</u>
3	Institutional/promotional advertising, selling expenses excludable from cost of service (Line 1 - Line 2)	2,053
4	Allocation to D.C. (Sales Expense ratio)	<u>0.3221</u>
5	Adjustment to D.C. operations and maintenance expense	<u>\$ (661)</u>
6	Adjustment to D.C. income tax expense	<u>\$ 74</u>
7	Adjustment to Federal income tax expense	<u>\$ 205</u>

POTOMAC ELECTRIC POWER COMPANY

District of Columbia
Ratemaking Adjustment Calculation
Twelve Months Ending September 30, 2011
(Six Months Actual; Six Months Projected)

(Thousands of Dollars)

Line No.	Adjustment 35 - Removal of Benning Environmental Liability Charge	
1	Total distribution-related charge for Benning environmental liability included in O&M expense	\$ 10,260
2	Allocation to D.C. (O&M less A&G ratio)	<u>0.3789</u>
3	Adjustment to D.C. allocated O&M expense	<u>\$ (3,888)</u>
4	Adjustment to D.C. income tax expense	<u>\$ 388</u>
5	Adjustment to Federal income tax expense	<u>\$ 1,225</u>

POTOMAC ELECTRIC POWER COMPANY

District of Columbia
Ratemaking Adjustment Calculation
Twelve Months Ending September 30, 2011
(Six Months Actual; Six Months Projected)

(Thousands of Dollars)

Line No.	Adjustment 36 - Inclusion of Interest Expense on Customer Deposits	
1	Interest on customer deposits at 2011 rate of 0.25%	<u>\$ 48</u>
2	Adjustment to D.C. income tax expense	<u>\$ (5)</u>
3	Adjustment to Federal income tax expense	<u>\$ (15)</u>

POTOMAC ELECTRIC POWER COMPANY

District of Columbia
Ratemaking Adjustment Calculation
Twelve Months Ending September 30, 2011
(Six Months Actual; Six Months Projected)

(Thousands of Dollars)

Line No.	Adjustment 37 - Reflection of Increased D.C. Water and Sewer Authority (WASA) Rates			
		Rate Effective 10/1/2010	Rate Effective 10/1/2011	Total Increase
	<u>Variable Rates</u>			
1	Water Service	\$ 3.10	\$ 3.29	
2	Sewer Service	3.79	4.01	
3	Right of Way Fee	0.14	0.15	
4	Payment in Lieu of Taxes (PILOT)	0.49	0.53	
5	Total cost per one hundred cubic feet (CCF)	\$ 7.52	\$ 7.98	\$ 0.46
6	Annual consumption (000's of CCF's)			3.965
7	Increase in D.C. operations and maintenance expense			\$ 2
	<u>Fixed Rates</u>			
8	Impervious Area Charge (IAC)	\$ 3.45	\$ 6.87	
9	Storm Water Fee	2.67	2.67	
10	Total cost per equivalent residential unit (ERU)	\$ 6.12	\$ 9.54	\$ 3.42
11	Pepco equivalent residential units (1000 ERU's)			2.6
12	Increase in D.C. operations and maintenance expense			\$ 105
13	Total adjustment to D.C. distribution-related O&M expense			\$ 107
14	Adjustment to D.C. income tax			\$ (11)
15	Adjustment to Federal income tax			\$ (34)

POTOMAC ELECTRIC POWER COMPANY

District of Columbia
Ratemaking Adjustment Calculation
Twelve Months Ending September 30, 2011
(Six Months Actual; Six Months Projected)

(Thousands of Dollars)

Line No.	Adjustment 38 - Reflection of Increase to D.C. Steel Plate Fees	
1	Adjustment to D.C. electric plant in service for capitalized D.C. steel plate fees not included in test period	\$ 9,500
2	Adjustment to D.C. accumulated depreciation	\$ (117)
3	Adjustment to D.C. accumulated deferred taxes (assuming 20-year tax depreciation)	\$ (145)
4	Adjustment to D.C. depreciation expense	\$ 234
5	Adjustment to D.C. income tax	\$ (23)
6	Adjustment to Federal income tax	\$ (74)

POTOMAC ELECTRIC POWER COMPANY

District of Columbia
Ratemaking Adjustment Calculation
Twelve Months Ending September 30, 2011
(Six Months Actual; Six Months Projected)

(Thousands of Dollars)

Line No.	Adjustment 39 - Reflection of Flotation Costs	
1	2012 Stock Issuance costs assigned to Pepco	\$ 1,932
2	Distribution-related Plant less AFUDC Allocator	0.8491
3	District of Columbia Plant less AFUDC Allocator	<u>0.4924</u>
4	Flotation costs charged to D.C. distribution-related O&M	808
5	Annual adjustment to amortize over a two-year period	<u>\$ 404</u>
6	Adjustment to D.C. income tax expense	<u>\$ (40)</u>
7	Adjustment to Federal income tax expense	<u>\$ (127)</u>
8	Adjustment to D.C. rate base to reflect average unamortized balance (net of ADT)	<u>\$ 355</u>

POTOMAC ELECTRIC POWER COMPANY

District of Columbia
Ratemaking Adjustment Calculation
Twelve Months Ending September 30, 2011
(Six Months Actual; Six Months Projected)

(Thousands of Dollars)

Line No.	Adjustment 40 - Interest Synchronization	
1	Ratemaking Adjustments to Average D.C. Rate Base	\$ 66,870
2	Weighted cost of debt @ March 31, 2011	<u>3.35%</u>
3	Pro-forma interest on Ratemaking Adjustments to D.C. Rate Base	2,240
4	Adjustment to D.C. income tax expense to reflect interest synchronization per Commission Order 9216	<u>\$ (223)</u>
5	Adjustment to Federal income tax expense to reflect interest synchronization per Commission Order 9216	<u>\$ (706)</u>

POTOMAC ELECTRIC POWER COMPANY

District of Columbia
Interest Synchronization of Unadjusted Cost of Service
Twelve Months Ending September 30, 2011
(Six Months Actual; Six Months Projected)

(Thousands of Dollars)

Line No.		
1	Unadjusted D.C. income tax expense for the twelve months ending September 30, 2011	\$ 2,525
2	Unadjusted D.C. portion of Federal income tax expense for the twelve months ending September 30, 2011	16,532
3	Unadjusted Average D.C. Rate Base	\$ 1,100,652
4	Weighted Cost of Debt @ March 31, 2011	<u>3.35%</u>
5	Pro-forma interest on Average D.C. Rate Base	36,872
6	less: Per Book D.C. Interest Expense	<u>41,179</u>
7	Adjustment to D.C. Taxable Income for Interest Synchronization	<u>\$ (4,307)</u>
8	Adjustment to Unadjusted D.C. Income Tax Expense for pro-forma interest expense	<u>\$ 430</u>
9	Adjustment to Unadjusted D.C. Federal Income Tax Expense for pro-forma interest expense	<u>\$ 1,357</u>
10	Unadjusted D.C. income tax reflecting synchronization of interest with unadjusted rate base (line 1 + line 8)	<u>\$ 2,955</u>
11	Unadjusted D.C. portion of federal income tax reflecting synchronization of interest with unadjusted rate base (line 2 + line 9)	<u>\$ 17,889</u>

POTOMAC ELECTRIC POWER COMPANY

District of Columbia
Analysis of Revenue Requirement -- Distribution Only
Twelve Months Ending September 30, 2011
(Six Months Actual, Six Months Projected)

(Thousands of Dollars)

	<u>Rate Base</u>	<u>Operating Income</u>	<u>Revenue Requirement</u>
Unadjusted amounts based on 10.75% return on equity	\$ 1,100,652	\$ 74,711	\$ 34,837
Adjustments			
1 Inclusion of projects completed and in service	\$ 2,766	\$ (40)	\$ 477
2 Inclusion of subtransmission plant	5,753	(134)	1,078
3 Recovery of upgrade to control center	2,224	(287)	819
4 Reflection of AMI meters	11,564	28	1,659
5 Reflection of AMI communications equipment & software	4,181	(471)	1,422
6 Recovery of AMI regulatory asset	28,352	(2,074)	7,732
7 Reflection of ongoing AMI operating costs & savings	-	600	(1,025)
8 Reflection of 2011 pension and OPEB expense	3,311	(436)	1,234
9 Recovery of tax on Medicare OPEB tax subsidy	209	(85)	176
10 Removal of F.C. 939 disallowed gainsharing and wages	(212)	20	(65)
11 Removal of supplemental executive retirement plans (SERP)	(448)	749	(1,346)
12 Removal of exempt and executive incentive plan costs	(2,584)	1,288	(2,583)
13 Annualization of software amortization	(352)	413	(758)
14 Removal of 25% of 69 kV lines	-	9	(15)
15 Reflection of ending amortization - F.C. 1053 rate case costs	(12)	55	(96)
16 Recovery of F.C. 1076 rate case costs	(562)	-	(83)
17 Recovery of F.C. XXXX rate case costs	1,150	(460)	956
18 Recovery of deferred customer education costs	(582)	-	(86)
19 Recovery of deferred AMI costs incurred through Dec 31, 2008	(35)	-	(5)
20 Reflection of ending amortization - flotation costs	(227)	59	(134)
21 Inclusion of credit facility costs	438	(201)	408
22 Annualization of wage increases	-	(545)	931
23 Annualization of employee health and welfare costs	-	(223)	381
24 Incremental customer care expense	-	(1,926)	3,292
25 Reflection of 3-year average regulatory expense	-	304	(520)
26 Reflection of 3-year average storm costs	-	448	(766)
27 Reflection of savings from post CE Divestiture ORP	-	481	(822)
28 Recovery of Organizational Review Project severance costs	2,343	785	(996)
29 Reflection of increased fuel costs	-	(88)	150
30 Proposed additional vegetation management spend in D.C.	-	(292)	499
31 Removal of adjustments to deferred compensation balances	-	261	(446)
32 Removal of employee association costs	-	14	(24)
33 Removal of industry contributions and membership fees	-	153	(261)
34 Removal of institutional advertising/selling expenses	-	382	(653)
35 Removal of Benning environmental liability charge	-	2,275	(3,888)
36 Inclusion of interest expense on customer deposits	-	(28)	48
37 Reflection of increased D.C. WASA rates	-	(62)	106
38 Reflection of D.C. steel plate fees	9,238	(137)	1,598
39 Reflection of 2012 Flotation costs	355	(237)	458
40 Interest synchronization	-	929	(1,588)
Total adjustments	\$ 66,870	\$ 1,527	\$ 7,264
Total revenue requirement based on 10.75% return on equity	<u>\$ 1,167,522</u>	<u>\$ 76,238</u>	<u>\$ 42,101</u>

POTOMAC ELECTRIC POWER COMPANY

District of Columbia Unadjusted Cash Working Capital
Twelve Months Ending September 30, 2011
(Six Months Actual, Six Months Projected)

				2005 STUDY		
				Test Year Amount	Lag Days	Annual Lag Dollars
<u>Operating Revenues (lag days on D.C. basis):</u>						
Residential	\$	61,376,971		58.76		\$ 3,606,510,816
RTM		1,174,217		44.45		52,193,946
MMA		13,467,469		52.70		709,735,616
General Service-LV		55,078,668		54.77		3,016,658,646
MGT-LV		-		-		-
General Service-HV		76,284		38.73		2,954,479
MGT-HV		-		-		-
Time of Day-LV		190,308,154		50.66		9,641,011,082
Time of Day-HV		78,260,935		52.64		4,119,655,618
Metro RT		9,414,992		48.92		460,581,409
Street Lighting		1,753,302		108.05		189,444,281
Total Distribution Revenue	\$	410,910,992		53.05		\$ 21,798,745,893
Rent from Electric Property	\$	1,803,693		-33.27		(60,008,866)
Forfeited Discounts		969,080		53.05		51,409,500
D.C. EATF		23,136		112.86		2,611,129
Misc Svc Revenues		159,985		4.54		726,332
Other		97,653		53.05		5,180,472
CEO Online - D.C. Portion		66,487		53.05		3,527,122
Billing Services - D.C. Portion		103,929		56.68		5,890,696
	\$	414,134,955				\$ 21,808,082,278
Composite Days Lag in D.C. Revenues				52.66		
<u>Operating Expenses:</u>						
PEPCO Labor - Wages		22,483,711		11.20		251,817,563
Other Operating Expenses		76,640,991		37.57		2,879,402,032
Control Center Lease		2,885,929		90.75		261,898,057
Other Taxes		-		-		-
Gross Receipts		-		-		-
Property Tax-D.C.		7,708,856		83.50		643,689,476
Property Tax-MD Montgomery		513,910		60.50		31,091,555
Property Tax-MD Prince George's		453,007		(90.50)		(40,997,134)
Property Tax-MD Charles		14,412		(59.50)		(857,514)
Property Tax-MD Other		51,297		(90.50)		(4,642,379)
Property Tax-VA Alexandria		90,246		51.00		4,602,546
Property Tax-VA Arlington		17,054		139.50		2,379,033
Property Tax-VA Fairfax		765		220.50		168,683
Property Tax-VA Pr William		3,683		75.50		278,067
MD Filing Fee		-		(28.00)		-
MD Delivery Tax		-		37.00		-
MD Universal Service Charge		-		28.04		-
MD Use Tax		-		35.71		-
MD Environmental Trust		-		37.54		-
MD Montg County Fuel & Energy Tax		-		61.63		-
MD Income Tax (current portion)		-		58.95		-
D.C. Business Improvement tax		157,760		(92.75)		(14,632,240)
D.C. Income Tax (current portion)		984,712		58.95		58,048,772
D.C. PSC Reimbursement		5,453,604		174.50		951,653,898
D.C. PSOS		21,569,222		(44.13)		(951,849,767)
D.C. RETF		17,897,759		35.71		639,128,974
D.C. Delivery Tax		88,091,806		35.71		3,145,758,392
D.C. Use Tax		(56,752)		35.71		(2,026,614)
Payroll Taxes-Federal Unemployment		17,102		(55.50)		(949,161)
Payroll Taxes-D.C. Unemployment		50,968		(54.85)		(2,795,595)
Payroll Taxes-MD Unemployment		33,879		(54.91)		(1,860,296)
Payroll Taxes-VA Unemployment		-		-		-
FICA-Social Security		1,674,077		13.73		22,985,077
Federal Income Tax		(12,739,169)		58.95		(750,974,013)
Total Distribution Expenses	\$	233,998,829				\$ 7,121,317,412
Composite Days Lag in Expenses				30.43		
Net Lag				22.23		
D.C. Average Daily Expense				\$ 641,093		
Cash Working Capital Allowance						\$ 14,251,497
Less:						
FIT/FICA Withholding		12,036		2.73		32,858
State Withholding		2,587		26.52		68,607
Subtotal						14,150,032
Plus:						
Imprest Funds						183,162
Total Distribution Working Capital Allowance						\$ 14,333,194

POTOMAC ELECTRIC POWER COMPANY

Computation of District of Columbia Tax Factors
Twelve Months Ending September 30, 2011

Line No.	Description	Statutory Tax Rate
1	D.C. Franchise Tax Rate	9.975%
2	Federal Income Tax Rate	35.00%

Line No.	Description	Computation	Tax Factor
3	D.C. Franchise Tax Factor	line 1	9.97500%
4	Federal Income Tax Factor	(100% - (line 3)) x line 2	31.50875%
5	Complement of Composite Tax Factor	100% - (line 3 + line 4)	58.51625%

L. J. HOOK
Direct Exhibit
DC P.S.C. - July, 2011

Introduced as:
PEPCO _____ (F)-2

POTOMAC ELECTRIC POWER COMPANY

Functionalized Cost of Service Elements
Twelve Months Ending September 30, 2011 (Six Months Actual, Six Months Projected)

Line No.	Item	Total System	Distribution Amount
	<u>Rate Base</u>		
1	Electric Plant in Service	\$ 5,738,700,416	\$ 4,834,040,623
2	Accumulated Depreciation	(2,536,489,567)	(2,157,727,268)
3	Accumulated Amortization	(93,300,800)	(60,547,609)
4	Plant Materials & Supplies	45,522,800	41,510,139
5	Net Prepaid Pension/OPEB Liability	134,714,335	121,040,830
6	Deferred Federal and State Tax Balance	(911,186,331)	(776,695,230)
7	Net Service Company Assets	11,140,957	10,010,150
	<u>Operating Income</u>		
8	Sale of Electricity	2,195,253,652	980,345,105
9	Other Revenues	23,328,443	8,196,590
10	O & M Expense	1,410,432,067	310,461,923
11	Depreciation and Amortization Expense	159,879,915	133,524,388
12	Taxes Other than Income Taxes	395,294,801	390,164,360
13	Maryland income tax	5,472,955	2,810,409
14	D.C. Income Tax	6,973,273	2,954,705
15	Federal Income Tax	45,446,273	19,248,714

Potomac Electric Power Company
Development of Distribution Cost of Service

Rate Base

1. Electric Plant

The distribution plant balance reflects historical data as recorded in the financial records of the Company. Included are all balances reflected in distribution accounts, plus general and intangible plant account balances allocated to distribution based on the Distribution Labor ratio.

2. Accumulated Depreciation

The distribution balance for Accumulated Depreciation reflects historical data as recorded in the financial records of the Company. Included are all balances reflected in distribution accounts, plus general accumulated depreciation balances allocated to distribution based on the Distribution Labor ratio.

3. Accumulated Amortization

The distribution balance for Accumulated Amortization reflects historical data as recorded in the financial records of the Company, allocated to distribution based on the Distribution Labor ratio.

4. Non-Fuel Stock Materials & Supplies

End-of-period balances for Materials & Supplies reflect data as recorded in the financial records of the Company, less amounts estimated to be related to transmission based on information available in the 2010 FERC Form 1.

5. Net Prepaid Pension/OPEB Liability

The prepaid pension asset/OPEB liability, net of associated deferred taxes, reflects historical data recorded in the financial records of the Company. The balance is allocated to distribution based on the Distribution Labor ratio.

6. Accumulated Deferred Income Taxes

The distribution balance for Accumulated Deferred Income Taxes reflects historical data recorded in the financial records of the Company. Rate base deferred taxes are allocated to distribution based on Plant ratios.

7. Customer Deposits

Customer Deposits reflect historical data recorded in the financial records of the Company. The balance is derived from a detailed analysis of accounting records.

8. Pepco Portion of Service Company Assets

The Pepco portion of the net service company assets reflects historical data recorded in the financial records of the Company. The net service company assets are allocated to distribution based on the Distribution Labor ratio.

9. Regulatory Assets

Reflects the average distribution related regulatory assets, net of associated deferred taxes, that are recorded in the financial records of the Company.

Potomac Electric Power Company
Development of Distribution Cost of Service

Operating Income

10. Sale of Electricity

Revenue comprised of billed District of Columbia jurisdictional distribution revenue, based on currently effective distribution rates.

11. Rent from Electric Property and Forfeited Discounts

Revenues were allocated to distribution based on detailed analysis.

12. Operation & Maintenance Expense

Operation & Maintenance expense for the District of Columbia distribution business reflects 6 months of historical data as recorded in the financial records of the Company plus six months of projected data. It reflects all distribution and customer accounts, plus a portion of the A&G accounts determined as follows: after elimination of costs in A&G accounts specifically identifiable as pertaining to the Company's Standard Offer Service business, the remaining costs are allocated to distribution based on the Distribution Labor ratio, with the exception of account 924 (property insurance), which is allocated based on plant less AFUDC, and accounts 928 (regulatory expense) and 904 (uncollectible expense), which are directly assigned based on detailed analysis. Distribution-related O&M is then allocated to the Company's retail jurisdictions based on the allocation methods historically in use in the District of Columbia.

13. Depreciation and Amortization Expense

Depreciation and amortization expense reflects 6 months of historical data as recorded in the financial records of the Company plus 6 months of projected data. The amounts include 100% of distribution accounts, plus an allocation of expenses in "general" functional accounts based on the Distribution Labor ratio.

14. Other Taxes

Taxes other than income taxes reflect 12 months of historical data as recorded in the financial records of the Company. Other taxes not directly assignable to distribution are allocated as follows: property taxes are allocated to distribution based on assessable plant; payroll taxes are allocated based on the Distribution Labor ratio.

15. Maryland State Income Tax

Maryland state income tax was determined by applying a Maryland apportioned income tax rate of 4.463% (based on the latest available tax return) to distribution-related system taxable income.

16. District of Columbia Income Tax

District of Columbia income tax was determined by applying a District of Columbia apportioned income tax rate 3.594% (based on the latest available tax return) to distribution-related system taxable income.

17. Federal Income Tax

Federal income tax was determined by applying the statutory rate of 35% to distribution-related system taxable income.

L. J. HOOK
Direct Exhibit
DC P.S.C. - July, 2011

Introduced as:
PEPCO _____ (F)-3

Potomac Electric Power Company

District of Columbia
Ratemaking Results - Distribution Only
Twelve Months Ending March 31, 2011

(Thousands of Dollars)

Line No.		Average (Unadjusted) (1)	Ratemaking Adjustments (2)	D.C. Adjusted (3)	Revenue to Achieve 10.75% Return on Equity (4)	Adjusted to Reflect 10.75% Return on Equity (5)
Rate Base						
1	Electric Plant in Service	\$ 2,335,245	\$ 21,196	\$ 2,356,441		\$ 2,356,441
2	Accumulated Depreciation	(822,980)	38	(822,942)		(822,942)
3	Accumulated Amortization	(26,575)	19,263	(7,312)		(7,312)
4	Materials and Supplies	20,007	-	20,007		20,007
5	Cash Working Capital	14,477	-	14,477		14,477
6	Accumulated Deferred Income Taxes	(463,145)	(7,329)	(470,474)		(470,474)
7	Prepaid Pension/OPEB Liab. (net of tax)	44,742	3,325	48,067		48,067
8	Customer Deposits	(21,090)	-	(21,090)		(21,090)
9	Pepco Portion of Servco Assets	5,409	1,900	7,309		7,309
10	Regulatory Assets	3,787	35,045	38,832		38,832
11	Unamortized Credit Facility Costs		345	345		345
12	Total Rate Base	<u>\$ 1,089,877</u>	<u>\$ 73,783</u>	<u>\$ 1,163,660</u>		<u>\$ 1,163,660</u>
Operating Revenues						
13	Sale of Electricity	\$ 412,306	\$ -	\$ 412,306		
14	Other Revenues	3,880		3,880		
15	Operating Revenues	<u>\$ 416,186</u>	<u>\$ -</u>	<u>\$ 416,186</u>	\$ 38,321	\$ 454,507
Operating Expenses						
16	Operation and Maintenance	\$ 113,667	\$ (13,269)	\$ 100,398		\$ 100,398
17	Depreciation	57,668	(8)	57,660		57,660
18	Amortization	3,836	5,754	9,590		9,590
19	Other Taxes	146,553	-	146,553		146,553
20	D.C. Income Tax	3,290	477	3,767	\$ 3,823	7,590
21	Federal Income Tax	18,502	1,600	20,102	12,074	32,176
22	Total Operating Expenses	<u>\$ 343,516</u>	<u>\$ (5,446)</u>	<u>\$ 338,070</u>	<u>\$ 15,897</u>	<u>\$ 353,967</u>
23	Operating Income	<u>\$ 72,670</u>	<u>\$ 5,446</u>	<u>\$ 78,116</u>	<u>\$ 22,424</u>	<u>\$ 100,540</u>
24	D.C. Jurisdictional Return on Rate Base	<u>6.67%</u>		<u>6.71%</u>		<u>8.64%</u>
Less Weighted Cost of:						
	Long Term Debt	3.35%		3.35%		3.35%
	Preferred Stock	0.00%		0.00%		0.00%
	Net amount available for common equity	3.32%		3.36%		5.29%
	Common Equity ratio	49.23%		49.23%		49.23%
	D.C. Jurisdictional Return on Equity	6.74%		6.83%		10.75%

Potomac Electric Power Company

District of Columbia Ratemaking Adjustments -- Distribution Only
Twelve Months Ending March 31, 2011

(Thousands of Dollars)

RMA No.	Ratemaking Adjustments	Rate Base (1)	Revenue (2)	Operation & Maintenance (3)	Depreciation (4)	Amortization (5)	Other Taxes (6)	DCIT (7)	FIT (8)
1	Inclusion of projects completed and in service				\$ 69			\$ (7)	\$ (22)
	Electric plant in service	\$ 2,817							
	Accumulated depreciation	(35)							
	Accumulated deferred taxes	(8)							
2	Inclusion of subtransmission plant				229			(23)	(72)
	Electric plant in service	6,424							
	Accumulated depreciation	(120)							
	Accumulated deferred taxes	(554)							
3	Recovery of upgrade to control center EMS	2,319				\$ 490		(49)	(154)
4	Reflection of AMI meters				(173)			17	55
	Electric plant in service	26,087							
	Accumulated depreciation	(1,064)							
	Accumulated deferred taxes	(6,543)							
5	Reflection of AMI communications equipment & software			\$ 422	63	350		(83)	(263)
	Electric plant in service	2,692							
	Servco assets	1,900							
	Accumulated depreciation	(32)							
	Accumulated amortization	(175)							
	Accumulated deferred taxes	(79)							
6	Recovery of AMI regulatory asset					3,545		(354)	(1,117)
	Regulatory asset, net of accumulated deferred taxes	30,125							
	Accumulated amortization	(1,773)							
7	Reflection of ongoing level of AMI operating costs and savings			(1,025)				102	323
8	Reflection of 2011 pension and OPEB expense	3,325		600				(57)	(190)
9	Recovery of tax on Medicare OPEB tax subsidy					147		(15)	(46)
	Regulatory asset, net of accumulated deferred taxes	215							
10	Removal of F.C. 939 disallowed gainsharing and wages				(34)			3	11
	Electric plant in service	(718)							
	Accumulated depreciation	485							
11	Removal of supplemental executive retirement plans (SERP)			(1,192)	(26)			115	386
	Electric plant in service	(537)							
	Accumulated depreciation	77							
12	Removal of exempt and executive incentive plan costs			(2,284)	(120)			226	762

Potomac Electric Power Company

District of Columbia Ratemaking Adjustments -- Distribution Only
Twelve Months Ending March 31, 2011

(Thousands of Dollars)

RMA No.	Ratemaking Adjustments	Rate Base (1)	Revenue (2)	Operation & Maintenance (3)	Depreciation (4)	Amortization (5)	Other Taxes (6)	DCIT (7)	FIT (8)
	Electric plant in service	(2,537)							
	Accumulated depreciation	209							
13	Annualization of software amortization					(940)		62	307
	Electric plant in service	(21,897)							
	Accumulated amortization	21,211							
14	Removal of 25% of 69 kV lines				(16)			2	5
	Electric plant in service	(635)							
	Accumulated depreciation	635							
15	Reflection of ending amortization - F.C. 1053 rate case costs			(218)				22	69
	Regulatory asset, net of accumulated deferred taxes	(57)							
16	Recovery of F.C. 1076 rate case costs			-				-	-
	Regulatory asset, net of accumulated deferred taxes	(562)							
17	Recovery of F.C. XXXX rate case costs			786				(78)	(248)
	Regulatory asset, net of accumulated deferred taxes	1,150							
18	Recovery of deferred customer education costs					-		-	-
	Regulatory asset, net of accumulated deferred taxes	(581)							
19	Recovery of deferred AMI costs incurred through Dec 31, 2008					-		-	-
	Regulatory asset, net of accumulated deferred taxes	(35)							
20	Reflection of ending amortization - flotation costs					101		(10)	(32)
	Regulatory asset, net of accumulated deferred taxes	(227)							
21	Inclusion of credit facility costs	345		275				(20)	(89)
22	Annualization of wage increases			821				(78)	(260)
23	Annualization of employee health and welfare costs			378				(36)	(120)
24	Incremental customer care expense			3,580				(340)	(1,134)
25	Reflection of 3-year average regulatory expense			(72)				7	23
26	Reflection of 3-year average storm costs			(3,636)				363	1,146
27	Reflection of savings from post CE Divestiture ORP			(2,453)				233	777
28	Recovery of Organizational Review Project severance costs			(4,971)		1,657		331	1,044
	Regulatory asset, net of accumulated deferred taxes	2,343							

Potomac Electric Power Company

District of Columbia Ratemaking Adjustments -- Distribution Only
Twelve Months Ending March 31, 2011

(Thousands of Dollars)

RMA No.	Ratemaking Adjustments	Rate Base (1)	Revenue (2)	Operation & Maintenance (3)	Depreciation (4)	Amortization (5)	Other Taxes (6)	DCIT (7)	FIT (8)
29	Reflection of increased fuel costs			195				(18)	(62)
30	Proposed additional vegetation management spend in D.C.			500				(50)	(158)
31	Removal of adjustments to deferred compensation balances			(682)				65	216
32	Removal of employee association costs			(27)				3	8
33	Removal of industry contributions and membership fees			(243)				23	77
34	Removal of institutional advertising/selling expenses			(526)				59	163
35	Removal of Benning environmental liability charge			(3,886)				388	1,224
36	Inclusion of interest expense on customer deposits			48				(5)	(15)
37	Reflection of increased D.C. WASA rates			107				(11)	(34)
38	Reflection of D.C. steel plate fees			234				(23)	(74)
	Electric plant in service	9,500							
	Accumulated depreciation	(117)							
	Accumulated deferred taxes	(145)							
39	Reflection of 2012 Flotation Costs	355				404		(40)	(127)
40	Interest synchronization							(247)	(779)
	Total Ratemaking Adjustments	<u>\$ 73,783</u>	<u>\$ -</u>	<u>\$ (13,269)</u>	<u>\$ (8)</u>	<u>\$ 5,754</u>	<u>\$ -</u>	<u>\$ 477</u>	<u>\$ 1,600</u>

POTOMAC ELECTRIC POWER COMPANY

District of Columbia
Ratemaking Adjustment Calculation
Twelve Months Ending March 31, 2011

(Thousands of Dollars)

Line No.	Adjustment 1 - Inclusion of Projects Completed and In-Service	
1	Adjustment to D.C. electric plant in service for items includable under legacy accounting system based on actual data available	\$ 2,817
2	Adjustment to D.C. accumulated depreciation	\$ (35)
3	Adjustment to D.C. accumulated deferred taxes (assuming 20-year tax depreciation)	\$ (8)
4	Adjustment to D.C. depreciation expense	\$ 69
5	Adjustment to D.C. income tax expense	\$ (7)
6	Adjustment to Federal income tax expense	\$ (22)

POTOMAC ELECTRIC POWER COMPANY

District of Columbia
Ratemaking Adjustment Calculation
Twelve Months Ending March 31, 2011

(Thousands of Dollars)

Line No.	Adjustment 2 - Inclusion of Subtransmission Plant			
	Job Descriptions	Balance	Reflected in 13-Mo Avg	Adjustment
1	Addition to Pepco distribution plant (subtransmission)	\$ 16,166		
2	Allocation to D.C. (Subtransmission Plant less AFUDC ratio)	0.4080		
3	Adjustment to D.C. electric plant in service	\$ 6,596	526	\$ 6,070
4	Adjustment to D.C. electric plant in service - AFUDC	368	14	354
5	Total adjustment to D.C. electric plant in service			<u>\$ 6,424</u>
6	Adjustment to D.C. accumulated depreciation	\$ (121)	(1)	<u>\$ (120)</u>
7	Adjustment to D.C. accumulated deferred taxes (assuming 20-year tax depreciation and 50% bonus depr)	\$ (554)	-	<u>\$ (554)</u>
8	Adjustment to D.C. depreciation expense			<u>\$ 229</u>
9	Adjustment to D.C. income tax expense			<u>\$ (23)</u>
10	Adjustment to Federal income tax expense			<u>\$ (72)</u>

POTOMAC ELECTRIC POWER COMPANY

District of Columbia
Ratemaking Adjustment Calculation
Twelve Months Ending March 31, 2011

(Thousands of Dollars)

Line No.	Adjustment 3 - Recovery of Upgrade to Control Center EMS	
1	Upgrade to Control Center EMS	\$ 12,065
2	Allocation to distribution (based on RTU count)	<u>74.3%</u>
3	Distribution-related upgrade to Control Center EMS	8,964
4	Allocation to D.C. (Distribution Plant less AFUDC ratio)	<u>0.4924</u>
5	District of Columbia distribution-related upgrade to Control Center EMS	4,414
6	Annual amortization expense (over life of original lease)	490
7	Amortization expense reflected in twelve months ending March 31, 2011	<u>-</u>
8	Adjustment to D.C. amortization expense	<u>\$ 490</u>
9	Adjustment to D.C. income tax	<u>\$ (49)</u>
10	Adjustment to Federal income tax	<u>\$ (154)</u>
11	Average unamortized balance, net of accumulated deferred tax, at March 31, 2012	<u>\$ 2,319</u>

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Line No.	Adjustment 4 - Reflection of AMI Meters			
		Full Value	13-month Avg Test Period	Adjustment
1	Adjustment to D.C. electric plant in service for capitalized AMI meters	\$ 27,522	\$ 1,435	\$ 26,087
2	Adjustment to D.C. accumulated depreciation	(1,070) ¹	(6) ²	\$ (1,064)
3	Adjustment to D.C. accumulated deferred taxes (100% bonus depreciation)	(9,464)	(2,921)	\$ (6,543)
4	Adjustment to D.C. depreciation expense	1,835 ¹	2,008 ^{2,3}	\$ (173)
5	Adjustment to D.C. income tax expense			\$ 17
6	Adjustment to Federal income tax expense			\$ 55

¹ Based on depreciation of AMI meters over 15-year period.

² Test Period AMI meters depreciated at currently approved non-AMI meter rate until 15-year rate is approved by the Commission.

³ Test Period includes legacy and AMI Meter depreciation expense.

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Line No.	Adjustment 5 - Reflection of AMI Communication Network and Software	Full Value	13-month Avg Test Period	Adjustment
	<u>Pepco Equipment and Software</u>			
1	Adjustment to EPIS for Communication Network (general plant)	\$ 943	\$ -	\$ 943
2	Adjustment to Depreciation Expense (assuming 15-year life)	63	-	63
3	Adjustment to Accumulated Depreciation	(32)	-	(32)
4	Adjustment to Accumulated Deferred Taxes	(79)	-	(79)
5	Adjustment to EPIS for software/system integration (CBSI)	1,749	-	1,749
6	Adjustment to Amortization Expense (assuming 5-year life)	350	-	350
7	Adjustment to Accumulated Amortization	(175)	-	(175)
	<u>PHI Service Company Software</u>			
8	Increase to Pepco-D.C. portion of Servco Assets for Service Company AMI software allocated to Pepco	2,111	- ¹	2,111
9	Adjustment to D.C. O&M expense for amortization charged to Pepco D.C.	422	- ²	422
10	Increase to Pepco-D.C. portion of Servco Assets for accumulated amortization on Service Company AMI software allocated to Pepco	(211)	-	<u>\$ (211)</u>
11	Adjustment to D.C. income tax expense			<u>\$ (83)</u>
12	Adjustment to Federal income tax expense			<u>\$ (263)</u>

¹ AMI-related Service Company software was not included in Servco assets reflected in unadjusted cost of service.

² Amortization of AMI-related Service Company software was not included in unadjusted cost of service.

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Line No.	Adjustment 6 - Recovery of AMI Regulatory Asset	Regulatory Asset Balance, before CCRF and ADT as of 3/31/2012	Accumulated Capital Cost Recovery Factor as of 3/31/2012	Total Recoverable
1	Loss on early retirement of non-AMI meters	\$ 45,635	\$ 1,289	\$ 46,924
2	Depreciation on non-AMI meters	(932)	(19)	(951)
3	Depreciation on AMI meters	590	10	600
4	Incremental (post-2008) costs	6,412	187	6,599
5	Total regulatory asset to be recovered over 15 years	\$ 51,705	\$ 1,467	\$ 53,172
6	Annual amortization (line 5 ÷ 15 years)			\$ 3,545
7	Balance in regulatory asset after one year (line 5 - line 6)			49,627
8	Adjustment to rate base for average unamortized balance (average of lines 5 & 7)			\$ 51,400
9	Adjustment to rate base for accumulated amortization			\$ (1,773)
10	Adjustment to rate base for accumulated deferred taxes			\$ (21,275)
11	Annual recovery (line 6)			\$ 3,545
12	Actual expense reflected in twelve months ending March 31, 2011			-
13	Adjustment to D.C. amortization expense (line 11 - line 12)			\$ 3,545
14	Adjustment to D.C. income tax			\$ (354)
15	Adjustment to Federal income tax			\$ (1,117)

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Line No.	Adjustment 7 - Reflection of AMI Ongoing Level of Incremental Costs/Savings	
1	Annualized ongoing level of incremental costs associated with D.C. AMI	\$ 3,050
2	Annualized ongoing level of incremental savings associated with D.C. AMI	<u>4,075</u> ¹
3	Adjustment to D.C. O & M expense	<u>\$ (1,025)</u>
4	Adjustment to D.C. income tax	<u>\$ 102</u>
5	Adjustment to Federal income tax	<u>\$ 323</u>

¹ Assumes remote disconnect/reconnect capability.

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Line No.	Adjustment 8 - Reflection of 2011 Pension and OPEB Expense	Pension	OPEB	Total
1	Average net-of-tax prepaid pension and OPEB balance - Pepco - at 12/31/2011	\$ 159,375	\$ (36,316)	\$ 123,059
2	Average net-of-tax prepaid pension and OPEB balance - Pepco - at 3/31/2011	156,042	(37,927)	118,115
3	Adjustment to net of tax prepaid pension and OPEB assets	\$ 3,333	\$ 1,611	4,944
4	Adjustment to include Pepco portion of Service Company net of tax prepaid pension/OPEB	\$ 10,096	\$ (6,263)	3,833
5	Allocation to D.C. (O&M less A&G ratio)			0.3788
6	Adjustment to D.C. net-of-tax prepaid pension and OPEB			\$ 3,325
7	2011 Pepco pension and OPEB expense includable in distribution-related O&M	\$ 11,661	\$ 7,787	\$ 19,448
8	2011 Service Company pension and OPEB expense chargeable to Pepco distribution-related O&M	4,870	5,021	9,891
9	Total 2011 pension and OPEB expense in Pepco distribution-related O&M	\$ 16,531	\$ 12,808	\$ 29,339
10	Pepco pension and OPEB expense included in distribution-related O&M for the twelve months ending March 31,2011	\$ 12,428	\$ 9,163	\$ 21,591
11	Service Company pension and OPEB expense charged to Pepco distribution-related O&M for the twelve months ending March 31,2011	4,497	1,667	6,164
12	Total pension and OPEB expense included in distribution-related O&M for the 12-months ending March 31,2011	\$ 16,925	\$ 10,830	\$ 27,755
13	Adjustment to Pepco distribution-related O&M pension and OPEB expense	\$ (394)	\$ 1,978	\$ 1,584
14	Allocation to D.C. (O&M less A&G ratio)			0.3788
15	Adjustment to D.C. operations and maintenance expense			\$ 600
16	Adjustment to D.C. income tax expense			\$ (57)
17	Adjustment to Federal income tax expense			\$ (190)

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Line No.	Adjustment 9 - Recovery of Tax on OPEB Medicare Tax Subsidy	Balance	ADT	Net
1	Tax on total Pepco OPEB Medicare tax subsidy	\$ 1,275		\$ 1,275
2	Allocation to Distribution (Labor ratio)	0.8985		0.8985
3	Distribution-related portion	1,146		1,146
4	Allocation to D.C. (O&M less A&G ratio)	0.3844		0.3844
5	Total D.C. allocated distribution-related portion	441	(183)	258
6	Annual recovery (line 5 ÷ 3 years)	147		147
7	Balance after one year	294	(122)	172
8	Average addition to rate base, net of deferred taxes			\$ 215
9	Actual expense reflected in twelve months ending March 31,2011			-
10	Adjustment to D.C. amortization expense (line 6 - line 9)			\$ 147
11	Adjustment to D.C. income tax			\$ (15)
12	Adjustment to Federal income tax			\$ (46)

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Line No.	Adjustment 10 - Removal of Capitalized Portion of Disallowed Corporate Gainsharing and Wages in Formal Case No. 939	
1	Capitalized portion of Corporate Gainsharing (& associated FICA) included in 13-month average unadjusted electric plant in service	\$ 1,539
2	Capitalized portion of 1994 and 1995 exempt wage increases in excess of 3% included in 13-month average unadjusted electric plant in service	<u>171</u>
3	Total capitalized expense included in electric plant in service	1,710
4	Allocation to Distribution (Plant less AFUDC ratio)	<u>0.8523</u>
5	Distribution related capitalized expense included in electric plant in service	1,457
6	Allocation to D.C. (Plant less AFUDC ratio)	<u>0.4931</u>
7	Adjustment to D.C. electric plant in service	<u><u>\$ (718)</u></u>
8	Accumulated depreciation included in 13 month average unadjusted results	\$ (1,243)
9	Allocation to Distribution (Depreciation less AFUDC ratio)	<u>0.8666</u>
10	Distribution related accumulated depreciation	(1,077)
11	Allocation to D.C. (Accumulated Depreciation less AFUDC ratio)	<u>0.3898</u>
12	Adjustment to D.C. accumulated depreciation	<u><u>\$ 485</u></u>
13	Depreciation expense included in unadjusted results for twelve months ending March 31, 2011	\$ 85
14	Allocation to Distribution (Depreciation less AFUDC ratio)	<u>0.8666</u>
15	Distribution related depreciation expense	74
16	Allocation to D.C. (Depreciation less AFUDC ratio)	<u>0.4650</u>
17	Adjustment to D.C. depreciation expense	<u><u>\$ (34)</u></u>
18	Adjustment to D.C. income tax expense	<u><u>\$ 3</u></u>
19	Adjustment to Federal income tax expense	<u><u>\$ 11</u></u>

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Line No.	Adjustment 11 - Removal of Non-Qualified Supplemental Executive Retirement Plans	
1	13 month average capitalized Pepco utility Non-Qualified Plan expense	\$ 810
2	13 month average capitalized Service Company Non-Qualified Plan expense charged to Pepco	469
3	Total 13 month average capitalized Non-Qualified Plan expense	1,279
4	Allocation to Distribution (Plant less AFUDC ratio)	0.8523
5	Distribution related capitalized Non-Qualified Plan expense	1,090
6	Allocation to D.C. (Plant less AFUDC ratio)	0.4931
7	Adjustment to D.C. electric plant in service	<u>\$ (537)</u>
8	13 month average accumulated depreciation	\$ (227)
9	Allocation to Distribution (Depreciation less AFUDC ratio)	0.8666
10	Distribution related portion of 13 month average accumulated depreciation	(197)
11	Allocation to D.C. (Accumulated Depreciation less AFUDC ratio)	0.3898
12	Adjustment to D.C. accumulated depreciation	<u>\$ 77</u>
13	Depreciation expense	\$ 64
14	Allocation to Distribution (Depreciation less AFUDC ratio)	0.8666
15	Distribution related portion of depreciation expense	55
16	Allocation to D.C. (Depreciation less AFUDC ratio)	0.4650
17	Adjustment to D.C. depreciation expense	<u>\$ (26)</u>
18	Pepco utility Non-Qualified Plan expense for the twelve months ending March 31,2011	\$ 1,590
19	Service Co. Non-Qualified Plan charged to Pepco for the twelve months ending March 31,2011	1,911
20	Total Non-Qualified Plan O&M expense for the twelve months ending March 31,2011	3,501
21	Allocation to Distribution (Labor ratio)	0.8985
22	Distribution-related operation & maintenance expense	3,146
23	Allocation to D.C. (O&M less A&G ratio)	0.3788
24	Adjustment to D.C. operations & maintenance expense	<u>\$ (1,192)</u>
25	Adjustment to D.C. income tax expense	<u>\$ 115</u>
26	Adjustment to Federal income tax expense	<u>\$ 386</u>

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Line No.	Adjustment 12 - Removal of Exempt and Executive Incentive Plans	
1	Average capitalized incentive costs in electric plant in service (EPIS)	\$ 6,038
2	Allocation to Distribution (Plant less AFUDC ratio)	<u>0.8523</u>
3	Average distribution related capitalized incentive costs in EPIS	5,146
4	Allocation to D.C. (Plant less AFUDC ratio)	<u>0.4931</u>
5	Adjustment to remove average capitalized incentive costs from D.C. EPIS	<u>\$ (2,537)</u>
6	Average capitalized incentive costs in accumulated depreciation	\$ (618)
7	Allocation to Distribution (Depreciation less AFUDC ratio)	<u>0.8666</u>
8	Average distribution related capitalized incentive costs in accumulated depreciation	(536)
9	Allocation to D.C. (Accumulated depreciation less AFUDC ratio)	<u>0.3898</u>
10	Adjustment to remove average capitalized incentive costs from D.C. accumulated depreciation	<u>\$ 209</u>
11	Average capitalized incentive costs in depreciation expense	\$ 299
12	Allocation to Distribution (Depreciation less AFUDC ratio)	<u>0.8666</u>
13	Average distribution related capitalized incentive costs in depreciation expense	259
14	Allocation to D.C. (Depreciation less AFUDC ratio)	<u>0.465</u>
15	Adjustment to remove average capitalized incentive costs from D.C. depreciation expense	<u>\$ (120)</u>
16	Distribution-related incentive costs charged to Pepco utility O&M for the twelve months ending March 31,2011	\$ 981
17	Distribution-related Service Co. incentive costs charged to Pepco utility O&M for the twelve months ending March 31,2011	<u>5,048</u>
18	Distribution-related incentive costs in Pepco O&M expense	6,029
19	Allocation to D.C. (O&M less A&G ratio)	<u>0.3788</u>
20	Adjustment to D.C. operations and maintenance expense to remove incentive costs	<u>\$ (2,284)</u>
21	Adjustment to D.C. income tax expense	<u>\$ 226</u>
22	Adjustment to Federal income tax expense	<u>\$ 762</u>

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Line No.	Adjustment 13 - Annualization of Software Amortization	Non-AFUDC	DC AFUDC	Total
	ADJUSTMENTS TO RATE BASE			
1	13-month average EPIS included in test period of software projects ending within one year	\$ 44,118	\$ 2,483	\$ 46,601
2	Annualization of EPIS for new software projects capitalized	(280)	6	(274)
3	Change in average EPIS	(44,398)	(2,477)	(46,875)
4	Allocation to Distribution (Labor ratio)	0.8985	0.8985	
5	Change in distribution-related average EPIS	(39,892)	(2,226)	(42,118)
6	Allocation to D.C. (Distribution Plant less AFUDC ratio)	0.4931	1.0000	
7	Adjustment to D.C. electric plant in service	\$ (19,671)	\$ (2,226)	\$ (21,897)
8	13-month average accumulated amortization included in test period for software projects ending within one year	\$ (43,021)	\$ (2,376)	\$ (45,397)
9	Annualization of accumulated amortization for new software projects capitalized	36	(1)	35
10	Change in average accumulated amortization	43,057	2,375	45,432
11	Allocation to Distribution (Labor ratio)	0.8985	0.8985	
12	Change in distribution-related average accumulated amortization	38,687	2,134	40,821
13	Allocation to D.C. (Distribution Plant less AFUDC ratio)	0.4931	1.0000	
14	Adjustment to D.C. accumulated amortization	\$ 19,077	\$ 2,134	\$ 21,211
	ANNUALIZATION OF AMORTIZATION EXPENSE			
15	Amortization expense included in test period for software projects ending by March 31,2011	\$ 1,659	\$ 202	\$ 1,861
16	Additional (annualized) expense for new projects capitalized	(55)	1	(54)
17	Adjustment to amortization expense	(1,714)	(201)	(1,915)
18	Allocation to Distribution (Labor ratio)	0.8985	0.8985	
19	Distribution-related adjustment to amortization expense	(1,540)	(181)	(1,721)
20	Allocation to D.C. (Distribution Plant less AFUDC ratio)	0.4931	1.0000	
21	Adjustment to D.C. amortization expense	\$ (759)	\$ (181)	\$ (940)
22	Adjustment to D.C. income tax expense			\$ 62
23	Adjustment to Federal income tax expense			\$ 307

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Line No.	Adjustment 14 - Removal of 25% of 69 kV Lines (F.C. 1076)	
1	Balance reflected in electric plant in service	\$ 2,540
2	Approximate percentage removed from service	<u>25%</u>
3	Adjustment to EPIS to exclude 25% of 69 kV lines removed from service	<u>\$ (635)</u>
4	Adjustment to D.C. accumulated depreciation	<u>\$ 635</u>
5	Adjustment to D.C. depreciation expense	<u>\$ (16)</u>
6	Adjustment to D.C. income tax expense	<u>\$ 2</u>
7	Adjustment to Federal income tax expense	<u>\$ 5</u>

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Line No.	Adjustment 15 - Reflection of Ending Amortization - F.C. 1053 Rate Case Costs	
1	Amortization expense in rate effective period	\$ -
2	Amortization expense included in test period	<u>218</u>
3	Adjustment to D.C. operation and maintenance expense	<u>\$ (218)</u>
4	Adjustment to D.C. income tax	<u>\$ 22</u>
5	Adjustment to Federal income tax	<u>\$ 69</u>
6	Average unamortized rate case costs, net of accumulated deferred tax, at March 31, 2012	\$ -
7	Average unamortized rate case costs, net of accumulated deferred tax, at March 31,2011	<u>57</u>
8	Adjustment to regulatory asset	<u>\$ (57)</u>

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Line No.	Adjustment 16 - Recovery of F.C. 1076 Rate Case Costs	
1	Total rate case costs deferred and amortized over a three-year period	\$ 2,880
2	Annual recovery (Line 1 ÷ 3 years)	960
3	Actual expense reflected in twelve months ending March 31,2011	<u>960</u>
4	Adjustment to D.C. operations and maintenance expense	<u>\$ -</u>
5	Adjustment to D.C. income tax	<u>\$ -</u>
6	Adjustment to Federal income tax	<u>\$ -</u>
7	Average unamortized rate case costs, net of accumulated deferred tax, at March 31, 2012	\$ 796
8	Average unamortized rate case costs, net of accumulated deferred tax, at March 31,2011	<u>1,358</u>
9	Adjustment to regulatory asset	<u>\$ (562)</u>

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Line No.	Adjustment 17 - Recovery of F.C. XXXX Rate Case Costs	
1	Total rate case costs to be deferred and amortized over a three-year period	\$ 2,358
2	Annual recovery (Line 1 ÷ 3 years)	786
3	Actual expense reflected in twelve months ending March 31,2011	-
4	Adjustment to D.C. operations and maintenance expense	<u>\$ 786</u>
5	Adjustment to D.C. income tax	<u>\$ (78)</u>
6	Adjustment to Federal income tax	<u>\$ (248)</u>
7	Average unamortized rate case costs, net of accumulated deferred tax, at March 31, 2012	<u>\$ 1,150</u>

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Line No.	Adjustment 18 - Recovery of Deferred Customer Education Costs (F.C. 1076)	
1	Total D.C. customer education costs deferred and amortized over a three-year period	\$ 2,980
2	Annual recovery (line 1 ÷ 3 years)	993
3	Actual expense reflected in twelve months ending March 31,2011	<u>993</u>
4	Adjustment to D.C. amortization expense	<u>\$ -</u>
5	Adjustment to D.C. income tax	<u>\$ -</u>
6	Adjustment to Federal income tax	<u>\$ -</u>
7	Average unamortized deferred customer education costs, net of accumulated deferred tax, at March 31, 2012	\$ 872
8	Average unamortized deferred customer education costs, net of accumulated deferred tax, at March 31,2011	<u>1,453</u>
9	Adjustment to regulatory asset, net of accumulated deferred tax	<u>\$ (581)</u>

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Line No.	Adjustment 19 - Recovery of Deferred AMI Costs Incurred through December 31, 2008	
1	Deferred D.C. AMI costs (incurred through December 31, 2008) approved for recoverable in Formal Case No. 1076	\$ 911
2	Annual recovery (line 1 ÷ 15 years)	\$ 61
3	Actual expense reflected in twelve months ending March 31,2011	<u>61</u>
4	Adjustment to D.C. amortization expense	<u>\$ -</u>
5	Adjustment to D.C. income tax	<u>\$ -</u>
6	Adjustment to Federal income tax	<u>\$ -</u>
7	Average unamortized AMI costs, net of accumulated deferred tax, at March 31, 2012	\$ 480
8	Average unamortized AMI costs, net of accumulated deferred tax, at March 31,2011	<u>515</u>
9	Adjustment to regulatory asset, net of accumulated deferred tax	<u>\$ (35)</u>

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Line No.	Adjustment 20 - Reflection of Ending Amortization - Flotation Costs for Common Stock Issuance	
1	Amortization expense in rate effective period	\$ 404
2	Amortization expense included in test period	<u>303</u>
3	Adjustment to D.C. amortization expense	<u>\$ 101</u>
4	Adjustment to D.C. income tax	<u>\$ (10)</u>
5	Adjustment to Federal income tax	<u>\$ (32)</u>
6	Average unamortized flotation costs, net of accumulated deferred tax, at March 31, 2012	\$ 177
7	Average unamortized flotation costs, net of accumulated deferred tax, at March 31, 2011	<u>404</u>
8	Adjustment to regulatory asset, net of accumulated deferred tax	<u>\$ (227)</u>

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Line No.	Adjustment 21 - Inclusion of Credit Facility Costs	
1	13-month average unamortized balance of start-up costs	\$ 820
2	Allocation to Distribution (Plant less AFUDC ratio)	<u>0.8523</u>
3	Adjustment to D.C. distribution plant	699
4	Allocation to D.C. (Plant less AFUDC ratio)	<u>0.4931</u>
5	Addition to D.C. rate base	<u><u>\$ 345</u></u>
6	Annual amortization of start-up costs	\$ 250
7	Annual cost of maintaining credit facility	<u>405</u>
8	Total expense	655
9	Allocation to Distribution (Plant less AFUDC ratio)	<u>0.8523</u>
10	Adjustment to Distribution-related expense	558
11	Allocation to D.C. (Plant less AFUDC ratio)	<u>0.4931</u>
12	Adjustment to D.C. operations & maintenance expense	<u><u>\$ 275</u></u>
13	Adjustment to D.C. income tax expense	<u><u>\$ (20)</u></u>
14	Adjustment to Federal income tax expense	<u><u>\$ (89)</u></u>

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Line No.	Adjustment 22 - Annualization of Wage Increases	Mgmt	Union	Total
	ANNUALIZATION OF TEST PERIOD INCREASES (3/1/11 MGMT, 6/1/11 UNION)			
	Distribution-related O&M wages/overtime, excluding one-time payments, before 3/1/11 for Management and before 6/1/11 for Union employees:			
1	Pepco	\$ 12,719	\$ 6,551	
2	Less: Incremental wages/overtime related to January 2011 storm	(262)	(1,028)	
3	Less: Incremental wages/overtime related to Summer 2010 storms	(342)	(1,892)	
4	Net amount	12,115	3,631	
5	Charged to Pepco from Service Company	30,390	765	
6	Less: Incremental wages/overtime related to January 2011 storm	(181)	(29)	
7	Less: Incremental wages/overtime related to Summer 2010 storms	(286)	(16)	
8	Net amount	29,923	720	
9	Test period percentage wage increase	3.01%	2.00%	
	Adjustment to annualize wage increases occurring in test period:			
10	Pepco (line 4 * line 9)	365	73	
11	Charged to Pepco from Service Company (line 8 * line 9)	901	14	
12	Total adjustment to annualize wage increases in test period	1,266	87	
	ADJUSTMENT TO REFLECT INCREASES WITHIN 12 MOS. OF TEST PERIOD			
13	Actual test year wages (distribution-related O&M) - Pepco	14,083	44,274	
14	Plus annualization (line 10)	365	73	
15	Less incremental storm-related labor (lines 2 and 3)	(604)	(2,920)	
16	Net amount	13,844	41,427	
17	Actual test year wages (distribution-related O&M) charged to Pepco from service co.	33,171	5,328	
18	Plus annualization (line 11)	901	14	
19	Less incremental storm-related labor (lines 6 and 7)	(467)	(45)	
20	Net amount	33,605	5,297	
21	Increase percent	3.00%	2.00%	
22	No. of months applicable	1	10	
	Adjustment to annualize wage increases occurring in test period:			
23	Pepco (line 16 * line 21 * line 22 ÷ 12)	35	690	
24	Charged to Pepco from service co. (line 20 * line 21 * line 22 ÷ 12)	84	88	
25	Total adjustment	119	778	
	ADJUSTMENT TO REFLECT END OF PERIOD HEADCOUNT PER F.C. 1053			
26	Annualized wages, net of incremental storm labor - Pepco (line 10 + line 23)	400	763	
	Employee Count-Pepco			
27	Average number of Pepco employees during test period	295	1,010	
28	Number of Pepco employees as of 3/31/11	331	1,043	
29	% end-of-period to average workforce level	112.20%	103.27%	
30	Adjustment ((line 26 * line 29)-line 26)	49	25	
31	Annualized wages, net of incremental storm labor charged to Pepco (line 11 + line 24)	985	102	
	Employee Count-Service company			
32	Avg no. of Service co employees during test period	1,425	347	
33	Number of Service co employees as of 3/31/11	1,201	347	
34	% end-of-period to average workforce level	84.28%	100.00%	
35	Adjustment ((line 31 * line 34)- line 31)	(155)	-	
	Total adjustment to wages:			
36	Pepco (line 10 + line 23 + line 30)	449	788	
37	Charged to Pepco from Service Company (line 11 + line 31 + line 35)	830	102	
38	Total adjustment	1,279	890	\$ 2,169
39	Allocation to D.C. (O&M less A&G ratio)	0.3788	0.3788	0.3788
40	Adjustment to D.C. Operations & Maintenance for wage increases	\$ 484	\$ 337	\$ 821
41	Adjustment to D.C. income tax expense			\$ (78)
42	Adjustment to Federal income tax expense			\$ (260)

POTOMAC ELECTRIC POWER COMPANY

District of Columbia
Ratemaking Adjustment Calculation
Twelve Months Ending March 31, 2011

(Thousands of Dollars)

Line No.	Adjustment 23 - Annualization of Employee Health & Welfare Costs			
	Plan	Test Period Amount	Rate Effective Period	Projected Change
1	Medical	\$ 12,969	\$ 14,007	\$ 1,038
2	Dental	1,114	1,169	55
3	Vision	377	396	19
4	Total change in health & welfare costs included in O&M expense			1,112
5	Allocation to distribution (Labor Ratio)			0.8985
6	Distribution-related adjustment to health & welfare costs			999
7	Allocation factor - DC O&M less A&G			0.3788
8	Adjustment to DC operations and maintenance expense			\$ 378
9	Adjustment to DC income tax expense			\$ (36)
10	Adjustment to Federal income tax expense			\$ (120)

POTOMAC ELECTRIC POWER COMPANY

District of Columbia
Ratemaking Adjustment Calculation
Twelve Months Ending March 31, 2011

(Thousands of Dollars)

Line No.	Adjustment 24 - Annualization of Incremental Customer Care Expense	Total Additional Expenditures	Reflected in Actual Months of Test Year	Adjustment
	Incremental customer care expense:			
1	Personnel	\$ 5,784	\$ 112	\$ 5,672
2	Infrastructure (hardware and software)	1,080	-	1,080
3	Storm preparedness	2,000	500	1,500
4	Customer education and research	1,200	-	1,200
5	Total annual recurring incremental expense			\$ 9,452
6	Allocation to D.C. (O&M less A&G ratio)			0.3788
7	Adjustment to D.C. operations and maintenance expense			\$ 3,580
8	Adjustment to D.C. income tax			\$ (340)
9	Adjustment to Federal income tax			\$ (1,134)

POTOMAC ELECTRIC POWER COMPANY

District of Columbia
Ratemaking Adjustment Calculation
Twelve Months Ending March 31, 2011

(Thousands of Dollars)

Line No.	Adjustment 25 - Reflection of 3-Year Average Non-Deferred Regulatory Costs	
		D.C. Direct
1	3/31/2009 regulatory expense (excludes F.C. 1076 deferred costs)	\$ 1,407
2	3/31/2010 regulatory expense (excludes F.C. 1076 deferred costs)	1,061
3	3/31/2011 regulatory expense	<u>1,342</u>
4	D.C. 3-year total	<u>\$ 3,810</u>
5	Three-year average D.C. regulatory expense	\$ 1,270
6	D.C. regulatory expense for the twelve months ending March 31, 2011	<u>1,342</u>
7	Adjustment to D.C. operations & maintenance expense	<u>\$ (72)</u>
8	Adjustment to D.C. income tax expense	<u>\$ 7</u>
9	Adjustment to Federal income tax expense	<u>\$ 23</u>

POTOMAC ELECTRIC POWER COMPANY

District of Columbia
Ratemaking Adjustment Calculation
Twelve Months Ending March 31, 2011

(Thousands of Dollars)

Line No.	Adjustment 26 - Reflection of 3-Year Average Storm Costs	System	Allocator	D.C.
	Storm restoration costs reflected in distribution related O&M expense:			
1	Twelve months ending March 31, 2009	\$ 5,261	0.3788	\$ 1,993
	Twelve months ending March 31, 2010			
	Directly assigned based on restorations			
2	February 2010 - Snow event incremental costs	\$ 7,083	0.0800	\$ 567
3	Allocable	1,117	0.3788	423
4	Total for twelve months ending March 31, 2010	<u>\$ 8,200</u>		<u>\$ 990</u>
	Twelve months ending March 31, 2011			
	Directly assigned based on restorations			
	July 25, 2010 - Storm event incremental costs	\$ 5,803	0.1100	\$ 638
	August 5, 2010 - Storm event incremental costs	509	0.0500	25
	August 12, 2010 - Storm event incremental costs	3,263	0.1600	522
5	January 2011 - Snow event incremental costs	10,333	0.0800	827
6	Allocable	13,022	0.3788	4,933
7	Total for twelve months ending March 31, 2011	<u>\$ 32,930</u>		<u>\$ 6,945</u>
8	Three-year average storm costs - D.C.			\$ 3,309
9	Adjustment to D.C. O&M expense to reflect 3-year average storm damage costs (Line 11 - Line 10)			<u>\$ (3,636)</u>
10	Adjustment to D.C. income tax expense			<u>\$ 363</u>
11	Adjustment to Federal income tax expense			<u>\$ 1,146</u>

POTOMAC ELECTRIC POWER COMPANY

District of Columbia
Ratemaking Adjustment Calculation
Twelve Months Ending March 31, 2011

(Thousands of Dollars)

Line No.	Adjustment 27 - Reflection of Savings from Organizational Review Project post-Conectiv Energy Divestiture	
	Estimated annual savings resulting from Organizational Review post-Conectiv Energy Divestiture:	
1	Labor-related savings	\$ 25,956
2	Non-Labor-related savings (Insurance, consulting, information technology)	1,860
3	Total annual PHI Corporate Center and Support Services savings	<u>\$ 27,816</u>
4	Percent of Corporate Center/Support Services charged to Pepco Power Delivery O&M	<u>34.55%</u>
5	Annual savings - Pepco Power Delivery O&M	9,610
6	Allocation to Distribution (Labor Ratio)	<u>0.8985</u>
7	Annual savings - distribution-related O&M	8,635
8	12*9)	(6,476)
9	Allocation to D.C. (O&M less A&G ratio)	<u>0.3788</u>
10	Adjustment to D.C. allocated O&M expense	<u>\$ (2,453)</u>
11	Adjustment to D.C. income tax expense	<u>\$ 233</u>
12	Adjustment to Federal income tax expense	<u>\$ 777</u>

POTOMAC ELECTRIC POWER COMPANY

District of Columbia
Ratemaking Adjustment Calculation
Twelve Months Ending March 31, 2011

(Thousands of Dollars)

Line No.	Adjustment 28 - Recovery of Organizational Review Project Severance	
1	Total distribution related severance costs to be deferred and amortized over a three-year period	\$ 13,120
2	Allocation to D.C. (O&M less A&G ratio)	<u>0.3789</u>
3	Adjustment to remove D.C. allocated severance costs in O&M expense	<u>\$ (4,971)</u>
4	D.C. allocated severance costs to be deferred and amortized over a three-year period	\$ 4,971
5	Annual recovery of D.C. allocated deferred severance costs (line 4 ÷ 3 years)	1,657
6	Actual amortization expense reflected in twelve months ending March 31, 2011	<u>-</u>
7	Adjustment to D.C. amortization expense	<u>\$ 1,657</u>
8	Adjustment to D.C. income tax	<u>\$ 331</u>
9	Adjustment to Federal income tax	<u>\$ 1,044</u>
10	Average unamortized deferred severance costs, net of accumulated deferred tax, at March 31, 2012	<u>\$ 2,343</u>

POTOMAC ELECTRIC POWER COMPANY

District of Columbia
Ratemaking Adjustment Calculation
Twelve Months Ending March 31, 2011

(Thousands of Dollars)

Line No.	Adjustment 29 - Reflection of Increased Fuel Costs		Bio-diesel Blend	Regular Unleaded	Total
1	Fuel costs reflected in twelve months ending March 31, 2011	\$	1,122	\$ 758	\$ 1,880
2	Usage in gallons		377.1	277.0	
3	Average price per gallon	\$	2.97	\$ 2.74	
4	Average price per gallon in rate effective period (based on May actual)	\$	3.71	\$ 3.80	
5	Fuel costs based on test period usage and current fuel prices	\$	1,399	\$ 1,053	\$ 2,452
6	Increase in operations and maintenance expense due to rising fuel costs				\$ 572
7	Allocation to Distribution (Labor Ratio)				<u>0.8985</u>
8	Increase in distribution operations and maintenance expense				514
9	Allocation to D.C. (O&M less A&G ratio)				<u>0.3788</u>
10	Adjustment to D.C. distribution-related O&M expense				<u>\$ 195</u>
11	Adjustment to D.C. income tax				<u>\$ (18)</u>
12	Adjustment to Federal income tax				<u>\$ (62)</u>

POTOMAC ELECTRIC POWER COMPANY

District of Columbia
Ratemaking Adjustment Calculation
Twelve Months Ending March 31, 2011

(Thousands of Dollars)

Line No.	Adjustment 30 - Proposed Additional Vegetation Management Activity - D.C.	
1	Incremental costs associated with proposed additional vegetation management in D.C.	<u>\$ 500</u>
2	Adjustment to D.C. income tax	<u>\$ (50)</u>
3	Adjustment to Federal income tax	<u>\$ (158)</u>

POTOMAC ELECTRIC POWER COMPANY

District of Columbia
Ratemaking Adjustment Calculation
Twelve Months Ending March 31, 2011

(Thousands of Dollars)

Line No.	Adjustment 31 - Removal of Adjustments to Deferred Compensation Balances	
1	Impact of adjustments to deferred compensation liability on O&M expense	\$ 2,003
2	Allocation to Distribution (Labor ratio)	<u>0.8985</u>
3	Distribution related impact of adjustments to deferred compensation liability on O&M expense	1,800
4	Allocation to D.C. (O&M less A&G ratio)	<u>0.3788</u>
5	Adjustment to D.C. operations and maintenance expense	<u>\$ (682)</u>
6	Adjustment to D.C. income tax expense	<u>\$ 65</u>
7	Adjustment to Federal income tax expense	<u>\$ 216</u>

POTOMAC ELECTRIC POWER COMPANY

District of Columbia
Ratemaking Adjustment Calculation
Twelve Months Ending March 31, 2011

(Thousands of Dollars)

Line No.	Adjustment 32 - Removal of Employee Association Costs	
1	Total employee association costs to be excluded per Formal Case 1076	\$ 80
2	Allocation to Distribution (Labor Ratio)	<u>0.8985</u>
3	Excludable employee association costs included in distribution O&M	<u>\$ 72</u>
4	Allocation to D.C. (O&M less A&G ratio)	<u>0.3788</u>
5	Adjustment to D.C. operations and maintenance expense	<u>\$ (27)</u>
6	Adjustment to D.C. income tax expense	<u>\$ 3</u>
7	Adjustment to Federal income tax expense	<u>\$ 8</u>

POTOMAC ELECTRIC POWER COMPANY

District of Columbia
Ratemaking Adjustment Calculation
Twelve Months Ending March 31, 2011

(Thousands of Dollars)

Line No.	Adjustment 33 - Removal of Industry Contributions and Membership Fees	
1	Industry contributions and membership fees for the twelve months ending March 31, 2011	\$ 714
2	Fees and contributions allowable per Order Nos. 9509 and 1053: American National Standards Institute	<u>1</u>
3	Total industry contributions and membership fees to be excluded	713
4	Allocation to Distribution (Labor Ratio)	<u>0.8985</u>
5	Excludable industry contributions & membership fees included in distribution O&M	641
6	Allocation to D.C. (O&M less A&G ratio)	<u>0.3788</u>
7	Adjustment to D.C. operations and maintenance expense	<u>\$ (243)</u>
8	Adjustment to D.C. income tax expense	<u>\$ 23</u>
9	Adjustment to Federal income tax expense	<u>\$ 77</u>

POTOMAC ELECTRIC POWER COMPANY

District of Columbia
Ratemaking Adjustment Calculation
Twelve Months Ending March 31, 2011

(Thousands of Dollars)

Line No.	Adjustment 34 - Removal of Institutional Advertising and Selling Expense	
1	Total advertising/selling expenses (FERC accounts 909, 911, 912, 913, 930.1) for the twelve months ending March 31, 2011	\$ 1,736
2	Expenses included above associated with informational activity	<u>102</u>
3	Institutional/promotional advertising, selling expenses excludable from cost of service (Line 1 - Line 2)	1,634
4	Allocation to D.C. (Sales Expense ratio)	<u>0.3221</u>
5	Adjustment to D.C. operations and maintenance expense	<u>\$ (526)</u>
6	Adjustment to D.C. income tax expense	<u>\$ 59</u>
7	Adjustment to Federal income tax expense	<u>\$ 163</u>

POTOMAC ELECTRIC POWER COMPANY

District of Columbia
Ratemaking Adjustment Calculation
Twelve Months Ending March 31, 2011

(Thousands of Dollars)

Line No.	Adjustment 35 - Removal of Benning Environmental Liability Charge	
1	Total distribution-related charge for Benning environmental liability included in O&M expense	\$ 10,260
2	Allocation to D.C. (O&M less A&G ratio)	<u>0.3788</u>
3	Adjustment to D.C. allocated O&M expense	<u>\$ (3,886)</u>
4	Adjustment to D.C. income tax expense	<u>\$ 388</u>
5	Adjustment to Federal income tax expense	<u>\$ 1,224</u>

POTOMAC ELECTRIC POWER COMPANY

District of Columbia
Ratemaking Adjustment Calculation
Twelve Months Ending March 31, 2011

(Thousands of Dollars)

Line No.	Adjustment 36 - Inclusion of Interest Expense on Customer Deposits	
1	Interest on customer deposits at 2011 rate of 0.25%	<u>\$ 48</u>
2	Adjustment to D.C. income tax expense	<u>\$ (5)</u>
3	Adjustment to Federal income tax expense	<u>\$ (15)</u>

POTOMAC ELECTRIC POWER COMPANY

District of Columbia
Ratemaking Adjustment Calculation
Twelve Months Ending March 31, 2011

(Thousands of Dollars)

Line

Adjustment 37 - Reflection of Increased D.C. Water and Sewer Authority (WASA) Rates

		Rate Effective 10/1/2010	Rate Effective 10/1/2011	Total Increase
	<u>Variable Rates</u>			
1	Water Service	\$ 3.10	\$ 3.29	
2	Sewer Service	3.79	4.01	
3	Right of Way Fee	0.14	0.15	
4	Payment in Lieu of Taxes (PILOT)	0.49	0.53	
5	Total cost per one hundred cubic feet (CCF)	\$ 7.52	\$ 7.98	\$ 0.46
6	Annual consumption (000's of CCF's)			3.965
7	Increase in D.C. operations and maintenance expense			\$ 2
	<u>Fixed Rates</u>			
8	Impervious Area Charge (IAC)	\$ 3.45	\$ 6.87	
9	Storm Water Fee	2.67	2.67	
10	Total cost per equivalent residential unit (ERU)	\$ 6.12	\$ 9.54	\$ 3.42
11	Pepco equivalent residential units (1000 ERU's)			2.6
12	Increase in D.C. operations and maintenance expense			\$ 105
13	Total adjustment to D.C. distribution-related O&M expense			\$ 107
14	Adjustment to D.C. income tax			\$ (11)
15	Adjustment to Federal income tax			\$ (34)

POTOMAC ELECTRIC POWER COMPANY

District of Columbia
Ratemaking Adjustment Calculation
Twelve Months Ending March 31, 2011

(Thousands of Dollars)

Line No.	Adjustment 38 - Reflection of Increase to D.C. Steel Plate Fees	
1	Adjustment to D.C. electric plant in service for capitalized D.C. steel plate fees not included in test period	<u>\$ 9,500</u>
2	Adjustment to D.C. accumulated depreciation	<u>\$ (117)</u>
3	Adjustment to D.C. accumulated deferred taxes (assuming 20-year tax depreciation)	<u>\$ (145)</u>
4	Adjustment to D.C. depreciation expense	<u>\$ 234</u>
5	Adjustment to D.C. income tax	<u>\$ (23)</u>
6	Adjustment to Federal income tax	<u>\$ (74)</u>

POTOMAC ELECTRIC POWER COMPANY

District of Columbia
Ratemaking Adjustment Calculation
Twelve Months Ending March 31, 2011

(Thousands of Dollars)

Line No.	Adjustment 39 - Reflection of Flotation Costs	
1	2012 Stock Issuance costs assigned to Pepco	\$ 1,932
2	Distribution-related Plant less AFUDC Allocator	0.8491
3	District of Columbia Plant less AFUDC Allocator	<u>0.4924</u>
4	Flotation costs charged to D.C. distribution-related O&M	808
5	Annual adjustment to amortize over a two-year period	<u>\$ 404</u>
6	Adjustment to D.C. income tax expense	<u>\$ (40)</u>
7	Adjustment to Federal income tax expense	<u>\$ (127)</u>
8	Adjustment to D.C. rate base to reflect average unamortized balance (net of ADT)	<u>\$ 355</u>

POTOMAC ELECTRIC POWER COMPANY

District of Columbia
Ratemaking Adjustment Calculation
Twelve Months Ending March 31, 2011

(Thousands of Dollars)

Line No.	Adjustment 40 - Interest Synchronization	
1	Ratemaking Adjustments to Average D.C. Rate Base	\$ 73,783
2	Weighted cost of debt @ March 31, 2011	<u>3.35%</u>
3	Pro-forma interest on Ratemaking Adjustments to D.C. Rate Base	2,472
4	Adjustment to D.C. income tax expense to reflect interest synchronization per Commission Order 9216	<u>\$ (247)</u>
5	Adjustment to Federal income tax expense to reflect interest synchronization per Commission Order 9216	<u>\$ (779)</u>

POTOMAC ELECTRIC POWER COMPANY

District of Columbia
Interest Synchronization of Unadjusted Cost of Service
Twelve Months Ending March 31, 2011

(Thousands of Dollars)

Line No.		
1	Unadjusted D.C. income tax expense for the twelve months ending March 31, 2011	\$ 2,801
2	Unadjusted D.C. portion of Federal income tax expense for the twelve months ending March 31, 2011	16,958
3	Unadjusted Average D.C. Rate Base	\$ 1,089,877
4	Weighted Cost of Debt @ March 31, 2011	<u>3.35%</u>
5	Pro-forma interest on Average D.C. Rate Base	36,511
6	less: Per Book D.C. Interest Expense	<u>41,411</u>
7	Adjustment to D.C. Taxable Income for Interest Synchronization	<u>\$ (4,900)</u>
8	Adjustment to Unadjusted D.C. Income Tax Expense for pro-forma interest expense	<u>\$ 489</u>
9	Adjustment to Unadjusted D.C. Federal Income Tax Expense for pro-forma interest expense	<u>\$ 1,544</u>
10	Unadjusted D.C. income tax reflecting synchronization of interest with unadjusted rate base (line 1 + line 8)	<u>\$ 3,290</u>
11	Unadjusted D.C. portion of federal income tax reflecting synchronization of interest with unadjusted rate base (line 2 + line 9)	<u>\$ 18,502</u>

POTOMAC ELECTRIC POWER COMPANY

District of Columbia
Analysis of Revenue Requirement -- Distribution Only
Twelve Months Ending March 31, 2011

(Thousands of Dollars)

	<u>Rate Base</u>	<u>Operating Income</u>	<u>Revenue Requirement</u>
Unadjusted amounts based on 10.75% return on equity	\$ 1,089,877	\$ 72,670	\$ 36,734
Adjustments			
1 Inclusion of projects completed and in service	\$ 2,774	\$ (40)	\$ 478
2 Inclusion of subtransmission plant	5,750	(134)	1,078
3 Recovery of upgrade to control center	2,319	(287)	833
4 Reflection of AMI meters	18,480	101	2,556
5 Reflection of AMI communications equipment & software	4,306	(489)	1,471
6 Recovery of AMI regulatory asset	28,352	(2,074)	7,731
7 Reflection of ongoing AMI operating costs & savings	-	600	(1,025)
8 Reflection of 2011 pension and OPEB expense	3,325	(353)	1,094
9 Recovery of tax on Medicare OPEB tax subsidy	215	(86)	179
10 Removal of F.C. 939 disallowed gainsharing and wages	(233)	20	(69)
11 Removal of supplemental executive retirement plans (SERP)	(460)	717	(1,293)
12 Removal of exempt and executive incentive plan costs	(2,328)	1,416	(2,764)
13 Annualization of software amortization	(686)	571	(1,077)
14 Removal of 25% of 69 kV lines	-	9	(15)
15 Reflection of ending amortization - F.C. 1053 rate case costs	(57)	127	(225)
16 Recovery of F.C. 1076 rate case costs	(562)	-	(83)
17 Recovery of F.C. XXXX rate case costs	1,150	(460)	956
18 Recovery of deferred customer education costs	(581)	-	(86)
19 Recovery of deferred AMI costs incurred through Dec 31, 2008	(35)	-	(5)
20 Reflection of ending amortization - flotation costs	(227)	(59)	67
21 Inclusion of credit facility costs	345	(166)	335
22 Annualization of wage increases	-	(483)	825
23 Annualization of employee health and welfare costs	-	(222)	379
24 Incremental customer care expense	-	(2,106)	3,599
25 Reflection of 3-year average regulatory expense	-	42	(72)
26 Reflection of 3-year average storm costs	-	2,127	(3,635)
27 Reflection of savings from post CE Divestiture ORP	-	1,443	(2,466)
28 Recovery of Organizational Review Project severance costs	2,343	1,939	(2,968)
29 Reflection of increased fuel costs	-	(115)	197
30 Proposed additional vegetation management spend in D.C.	-	(292)	499
31 Removal of adjustments to deferred compensation balances	-	401	(685)
32 Removal of employee association costs	-	16	(27)
33 Removal of industry contributions and membership fees	-	143	(244)
34 Removal of institutional advertising/selling expenses	-	304	(520)
35 Removal of Benning environmental liability charge	-	2,274	(3,886)
36 Inclusion of interest expense on customer deposits	-	(28)	48
37 Reflection of increased D.C. WASA rates	-	(62)	106
38 Reflection of D.C. steel plate fees	9,238	(137)	1,597
39 Reflection of 2012 Flotation costs	355	(237)	457
40 Interest synchronization	-	1,026	(1,753)
Total adjustments	\$ 73,783	\$ 5,446	\$ 1,587
Total revenue requirement based on 10.75% return on equity	<u>\$ 1,163,660</u>	<u>\$ 78,116</u>	<u>\$ 38,321</u>

POTOMAC ELECTRIC POWER COMPANY

District of Columbia Unadjusted Cash Working Capital
Twelve Months Ending March 31, 2011

2005 STUDY			
	Test Year Amount	Lag Days	Annual Lag Dollars
<u>Operating Revenues (lag days on D.C. basis):</u>			
Residential	\$ 61,455,344	58.76	\$ 3,611,116,026
RTM	1,137,314	44.45	50,553,605
MMA	13,901,810	52.70	732,625,409
General Service-LV	54,065,230	54.77	2,961,152,623
MGT-LV	-	-	-
General Service-HV	78,078	38.73	3,023,961
MGT-HV	-	-	-
Time of Day-LV	191,626,269	50.66	9,707,786,785
Time of Day-HV	78,906,286	52.64	4,153,626,886
Metro RT	9,408,459	48.92	460,261,836
Street Lighting	1,727,056	108.05	186,608,396
Total Distribution Revenue	<u>\$ 412,305,846</u>	53.04	<u>\$ 21,866,755,527</u>
Rent from Electric Property	\$ 1,541,593	-33.27	(51,288,799)
Forfeited Discounts	1,271,453	53.04	67,431,891
D.C. EATF	437,837	112.86	49,414,284
Misc Svc Revenues	160,990	4.54	730,895
Other	98,559	53.04	5,227,106
CEO Online - D.C. Portion	66,784	53.04	3,541,909
Billing Services - D.C. Portion	89,315	56.68	5,062,374
	<u>\$ 415,972,377</u>		<u>\$ 21,946,875,187</u>
Composite Days Lag in D.C. Revenues		<u>52.76</u>	
<u>Operating Expenses:</u>			
PEPCO Labor - Wages	22,105,621	11.20	247,582,955
Other Operating Expenses	77,087,855	37.57	2,896,190,712
Control Center Lease	2,885,167	90.75	261,828,905
Other Taxes			
Gross Receipts	-	-	-
Property Tax-D.C.	7,360,599	83.50	614,610,017
Property Tax-MD Montgomery	518,120	60.50	31,346,260
Property Tax-MD Prince George's	459,869	(90.50)	(41,618,145)
Property Tax-MD Charles	14,771	(59.50)	(878,875)
Property Tax-MD Other	48,871	(90.50)	(4,422,826)
Property Tax-VA Alexandria	86,586	51.00	4,415,886
Property Tax-VA Arlington	15,290	139.50	2,132,955
Property Tax-VA Fairfax	746	220.50	164,493
Property Tax-VA Pr William	3,514	75.50	265,307
MD Filing Fee	-	(28.00)	-
MD Delivery Tax	-	37.00	-
MD Universal Service Charge	-	28.04	-
MD Use Tax	-	35.71	-
MD Environmental Trust	-	37.54	-
MD Montg County Fuel & Energy Tax	-	61.63	-
MD Income Tax (current portion)	-	58.95	-
D.C. Business Improvement tax	157,761	(92.75)	(14,632,333)
D.C. Income Tax (current portion)	2,224,421	58.95	131,129,618
D.C. PSC Reimbursement	5,180,540	174.50	904,004,230
D.C. PSOS	21,765,165	(44.13)	(960,496,731)
D.C. RETF	20,420,337	35.71	729,210,234
D.C. Delivery Tax	88,908,903	35.71	3,174,936,926
D.C. Use Tax	(45,841)	35.71	(1,636,982)
Payroll Taxes-Federal Unemployment	17,329	(55.50)	(961,760)
Payroll Taxes-D.C. Unemployment	50,122	(54.85)	(2,749,192)
Payroll Taxes-MD Unemployment	33,317	(54.91)	(1,829,436)
Payroll Taxes-VA Unemployment	-	-	-
FICA-Social Security	1,557,160	13.73	21,379,807
Federal Income Tax	(1,393,218)	58.95	(82,130,201)
Total Distribution Expenses	<u>\$ 249,463,005</u>		<u>\$ 7,907,841,824</u>
Composite Days Lag in Expenses		31.70	
Net Lag		21.06	
D.C. Average Daily Expense		\$ 683,460	
Cash Working Capital Allowance			\$ 14,393,668
Less:			
FIT/FICA Withholding	11,834	2.73	32,307
State Withholding	2,544	26.52	67,467
Subtotal			<u>14,293,894</u>
Plus:			
Imprest Funds			183,423
Total Distribution Working Capital Allowance			\$ 14,477,317

POTOMAC ELECTRIC POWER COMPANY

Computation of District of Columbia Tax Factors
Twelve Months Ending March 31, 2011

Line No.	Description	Statutory Tax Rate
1	D.C. Franchise Tax Rate	9.975%
2	Federal Income Tax Rate	35.00%

Line No.	Description	Computation	Tax Factor
3	D.C. Franchise Tax Factor	line 1	9.97500%
4	Federal Income Tax Factor	(100% - (line 3)) x line 2	31.50875%
5	Complement of Composite Tax Factor	100% - (line 3 + line 4)	58.51625%

L. J. HOOK
Direct Exhibit
DC P.S.C. - July, 2011

Introduced as:
PEPCO _____ (F) -4

Potomac Electric Power Company

PEPCO (F) - 4

Analysis of Changes in Average Unadjusted District of Columbia Jurisdictional Rate Base and Operating Income
Between the Twelve Months Ended March 31, 2010
and the Twelve Months Ending September 30, 2011 (Six Months Actual; Six Months Projected)

(Thousands of Dollars)

Line No.		12 Months Ended March 2011	12 Months Ending September 2011	Increase (Decrease)	Explanation of Change
Rate Base					
1	Electric Plant in Service	\$ 2,335,245	\$ 2,380,818	\$ 45,573	Increased cut-in's reflected for projected 6 months Increased depreciation due to higher plant balance and retirement of legacy meters
2	Accumulated Depreciation	(822,980)	(845,691)	(22,711)	
3	Accumulated Amortization	(26,575)	(27,677)	(1,102)	
4	Materials and Supplies	20,007	20,597	590	
5	Cash Working Capital	14,477	14,333	(144)	
6	Accumulated Deferred Income Taxes	(463,145)	(474,502)	(11,357)	Additional bonus depreciation beginning in 2011
7	Prepaid Pension/OPEB Liab. (net of tax)	44,742	45,862	1,120	
8	Customer Deposits	(21,090)	(21,060)	30	
9	Pepco Portion of Servco Assets	5,409	4,929	(480)	
10	Regulatory Assets	3,787	3,043	(744)	
11	Total Rate Base	<u>\$ 1,089,877</u>	<u>\$ 1,100,652</u>	<u>\$ 10,775</u>	
Operating Revenues					
12	Sale of Electricity	\$ 412,306	\$ 410,911	\$ (1,395)	
13	Other Revenues	3,880	3,224	(656)	
14	Operating Revenues	<u>\$ 416,186</u>	<u>\$ 414,135</u>	<u>\$ (2,051)</u>	
Operating Expenses					
15	Operation and Maintenance	\$ 113,667	\$ 112,028	\$ (1,639)	
16	Depreciation	57,668	59,290	1,622	
17	Amortization	3,836	3,519	(317)	
18	Other Taxes	146,553	143,743	(2,810)	Reduction in EATF surcharge, partially offset by increase in SETF and RADS surcharges
19	D.C. Income Tax	3,290	2,955	(335)	
20	Federal Income Tax	18,502	17,889	(613)	
21	Total Operating Expenses	<u>\$ 343,516</u>	<u>\$ 339,424</u>	<u>\$ (4,092)</u>	
22	Operating Income	<u>\$ 72,670</u>	<u>\$ 74,711</u>	<u>\$ 2,041</u>	
23	D.C. Jurisdictional Return on Rate Base	<u>6.67%</u>	<u>6.79%</u>		

L. J. HOOK
Direct Exhibit
DC P.S.C. - July, 2011

Introduced as:
PEPCO _____ (F) -5

POTOMAC ELECTRIC POWER COMPANY

Balance Sheet
As of March 31, 2011

Assets

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Current Assets

131000	Cash - General	5,486,142.03
131001	Cash - Clearing	(9,009.31)
131050	Cash-In Transit - CIS	2,233,832.60
135200	Employee Advances	-
	Cash & Cash Equivalents	7,710,965.32
142000	Customer Accounts Rec - General	(898,727.70)
142001	Customer Accounts Rec - Credit Balances	19,367,260.89
142070	Customer Accounts Rec - Washington DC	65,558,858.65
142120	Customer Accounts Rec - MD	113,150,074.47
142130	Customer Accounts Rec - VA	51,190.91
142210	AR-Supply Portion (all customers)	58,870,001.57
142350	Customer Accounts Receivable - Cash Clearing	(1,788,651.05)
142430	Customer Accounts Rec - Miscellaneous Service Rev	16,687.70
142450	Customer Accounts Rec-Merchandise	159,200.23
143000	Accounts Receivable - General	3,046,174.86
143100	A/R - Employee Purchases	(1,043.43)
143118	A/R - Tuition Aid Reimbursement - Former Employees	58,528.22
143119	A/R - Tuition Aid - Current Employees	10,848.46
143200	A/R-PJM Interchange	3,249,757.93
143703	Accounts Receivable - SOS Suppliers	20,813.19
143704	Accounts Receivable - 401K Match	(0.02)
143716	AR-OTC Margin Deposits	-
143900	Accounts Receivable Special Billing Unbilled	6,009,748.80
143901	Accounts Receivable Special Billing	12,428,553.63
171900	I/C Interest Receivable	29,837.85
172000	Rents Receivable - General	15,951.12
172901	Rents Receivable - CATV(Reconciliation)	3,427,697.46
172902	Rents Receivable-Special Billing (Reconciliation)	82,078.55
173100	Accrued Utility Revenue - Unbilled Revenue	80,980,829.05
	Accounts Receivable	363,845,671.34
144000	PROVISION FOR UNCOLLECTIBLE ACCOUNTS	(19,100,782.44)
	Provision for Uncollectible	(19,100,782.44)
146003	I/C - Pepco/PES - Retail Access	(19,652,128.55)
146004	I/C - Pepco/PES - Special Billing Contract Work	(2,804,177.16)
146506	I/C-PEPCO / ACE 7000/1500	12,295.99
146974	I/C-PEPCO / PEPCO Energy Services 7000/7700	(24,691,045.81)
146975	I/C-PEPCO / PEPCO Holdings, Inc. 7000/9959	173,207.27
146976	I/C-PEPCO / PHISC 7000/9000	(17,665,377.01)
146996	I/C-PEPCO / DPL 7000/1000	(231,955.88)
	Accounts Receivable from Associated Companies	(64,859,181.15)
154000	Material & Operating Supplies - General	45,207,770.42
154080	Inventory - Blocked Stock	(402.64)

POTOMAC ELECTRIC POWER COMPANY

Balance Sheet
As of March 31, 2011

158135	Renewable Energy Credits - General	27,508.00
163000	Stores Exp Undistributed - General	2,613,009.13
	Inventories - Fuel, Materials and Supplies	47,847,884.91
190700	FIN 48 Federal Interest & Tax Receivable-Current	(0.40)
	Interest & Tax Asset-Uncertain Tax Positions	(0.40)
190710	Federal Income Tax Receivable-Current	30,391,021.69
190760	State Income Tax Receivable-Current	1,273,432.00
	Income Taxes Receivable	31,664,453.69
165409	Prepayments - Income Taxes	47,375,101.19
	Prepayments of Income Taxes	47,375,101.19
135001	Working Funds - General	10,000.00
135161	Working Funds - Benefit Providers	404,000.00
165000	Prepayments - General	1,527,692.26
165100	Prepayments - Other Taxes	9,214,168.43
165206	Prepayments - Workmen's Compensation	508,128.27
165213	Prepayments - Ordinary Life	580,565.07
165406	Prepayments-Postage General	170,735.77
190055	Deferred Income Tax - Federal - NOL's - Short-term	(1,273,404.00)
190110	Deferred Income Tax Asset - Federal - Short-term	10,538,068.00
190150	Deferred Inc Tax Asset-Federal-UTPs/Eff Sttld-Cur	(10.01)
190210	Deferred Income Tax Asset - State - Short-term	2,696,150.00
	Prepaid Expenses and Other	24,376,093.79
	Total	438,860,206.25
	Investments and Other Assets	
182250	Regulatory Assets - Asset Retirement Obligation	270,860.31
182300	Other Regulatory Assets - General	11,022,525.42
182345	Reg Assets-MD Bill Stabilization Aj (BSA) Deferral	6,693,565.10
182346	Reg Assets-DC Bill Stabilization Aj (BSA) Deferral	1,249,288.16
182366	DSM - Energy Efficient Products - Community	12,060,095.61
182394	Regulatory Assets - DSM - Direct Load Control Prog	6,638,063.54
182500	Other Reg Assets - Income Tax Recov thru Rates	48,000,698.57
182508	Other Reg Assets - Third Party Supplier Recovery	(939,905.99)
182515	Regulatory Asset - Wks Comp/LT Disability Accrual	29,527,387.78
182521	Other Regulatory Assets - MD SOS Transmission Cost	36,331.22
182522	Other Reg Assets - MD SOS Administrative Charge	2,702,201.40
182524	Other Regulatory Assets - DC SOS Energy Costs	6,722,969.75
182526	Other Reg Assets - DC SOS Administrative Charge	-
182538	Reg Assets-FERC Formula Rate Adj-Transmission Svc	1,401,780.98
182540	Regulatory Asset - Blueprint for the Future	5,230,432.10
182544	Regulatory Asset-Return on Blueprint Reg Asset-DC	44,764.00
182545	Regulatory Asset -Control Center Replacement Parts	5,681,766.38
182546	Regulatory Asset -Control Center - EMS	12,350,697.89
182547	Regulatory Asset- District of Columbia (DC) Meters	7,847,438.79

POTOMAC ELECTRIC POWER COMPANY

Balance Sheet
As of March 31, 2011

182548	Regulatory Asst-Meters-Incremental Depreciation-DC	30,296.89
182549	Regulatory Asset-Return on Blueprint Reg Asset-MD	67,216.00
182599	Regulatory Asst-Meters-Accelerated Depreciation	16,943,245.00
186140	AMI - Recoverable	849,919.52
189000	Unamortized Loss on Reacquired Debt - General	5,774,837.57
189300	Unamortized Loss - Pollution Bonds	240,289.99
189400	Unamortized Loss - First Mortgage Bonds	26,280,337.36
Regulatory Assets		206,727,103.34
123265	Investment In POM Holdings	1,000.00
Investment in Consolidated Companies		1,000.00
186308	Prepaid Pension Costs	308,114,478.84
Prepaid Pension Expense		308,114,478.84
190800	FIN48 Federal Interest & Tax Receivable-Noncurrent	(0.41)
190850	FIN48 State Interest & Tax Receivable-Noncurrent	(0.76)
Interest & Tax Asset-Uncertain Tax Positions		(1.17)
190810	Federal Income Tax Receivable-Non-current	18,953,704.66
190860	State Income Tax Receivable-Non-current	8,376,891.70
Income Taxes Receivable		27,330,596.36
128116	Other Special Funds-Deferred Comp	20,833,316.94
128117	Other Special Funds - Deferred Comp - Trust 2	1,912,149.67
128118	Other Special Funds - Deferred Comp PHI	1,974,787.93
134000	Other Special Deposits - General	61.35
181000	Unamortized Debt Expense - General	96,039.21
181100	Unamortized Debt Expense - First Mortgage Bonds	15,392,667.72
184200	Clearing supplier discounts (Net method)	4,525.65
184300	Clearing Accounts AP Cash Return	3,318.00
184310	Suspense Account - Payroll	158,185.45
186000	Miscellaneous Deferred Debits - General	931,367.61
186120	Suspense - Asset Management	2,721.95
186250	Misc Deferred Debits-Officer's Life Insurance	20,288,465.18
186251	Misc Deferred Debits-COLI Plan	77,241,395.08
186611	Construction Related	0.21
242413	Loans against Life Insurance Contract Investments	(55,549,791.29)
Other		83,289,210.66
Total		625,462,388.03
Property, Plant, and Equipment		
101100	Property under Capital Lease (Manual)	154,596,184.74
101250	Asset Retirement Obligation (ARO) Asset	283,373.00
101410	Plant In Service - Electric	5,484,211,144.45
101610	Plant In Service - Intangible	92,057,206.26
105400	Plant Held for Future Use - General	8,961,806.04
106410	Plant Unclassified-Electric	103,881,667.76

POTOMAC ELECTRIC POWER COMPANY

Balance Sheet
As of March 31, 2011

107100	Assets Under Construction Accruals	1,992,000.00
107200	Assets Under Construction Adjustments	(1,730,179.81)
107300	Asset Under Construction - New Load Accruals	5,848,401.34
107302	Asset Under Construction - Emergency Operate Accl	-
107303	Asset Under Construction - Emergency Op Bay Accl	126,000.00
107410	Asset Under Construction-Electric	336,103,823.01
107910	Capital Project Clearing - Electric	-
121400	Plant In Service - Non Utility	81,720,040.19
121910	Capital Project Clearing - Non Utility	-
Property, Plant and Equipment		6,268,051,466.98
101110	Capital Lease - Amortization (Manual)	(63,420,309.58)
108019	Insurance Proceeds	(1,192,453.39)
108200	Accum Depreciation - Adjustments	(16,943,245.01)
108250	Accumulated Reserve - Asset Retirement Obligation	(80,489.28)
108410	Accumulated Provision for Depreciation - Electric	(2,410,348,199.08)
108411	Accumulated Cost of Removal (RWIP) - Electric	11,855,296.53
108413	Salvage - Electric	(438,495.90)
111620	Accumulated Amortization - Intangible	(91,258,381.63)
122400	Accumulated Depreciation - Non Utility	(63,829,314.59)
Accumulated Depreciation & Amortization		(2,635,655,591.93)
Total		3,632,395,875.05
Total Assets		4,696,718,469.33

Capitalization & Liabilities

=====

Current Liabilities

233059	Money Pool - PEPCO	107,947,083.29
Money Pool Lendings		107,947,083.29
184100	Clearing-Goods Received/Invoice Received	(737,651.02)
232000	Accounts Payable Reconciliation - General	(32,938,404.87)
232004	Cashed Checks - A/P	212,793.99
232012	Outstanding Checks - A/P	(5,450,304.94)
232020	Outstanding Checks-Customer Refund-Bank of NY	(2,244,613.75)
232022	Outstanding Checks - Overdraft Offset	9,009.31
232100	Accounts Payable-Consignment Sale	(9,084.34)
232150	Accounts Payable - Internet Returns	(24,688.27)
232200	Accounts Payable Reconciliation Employee Advances	(336.66)
232400	Accounts Payable Accrual	(2,065,980.24)
232401	Accounts Payable - Standing Accruals	(106,654.78)
232402	Accounts Payable Accrual-Corporate	(4,658,945.35)
232430	Accounts Payable Accrual - Purchased Power	(19,232,324.95)
232456	Accounts Payable-Monthly Accruals	(30,188,569.26)
232500	Accounts Payable-Wages Payable	(196,968.09)
232502	Accounts Payable-Accrued Payroll	(3,801,537.00)

POTOMAC ELECTRIC POWER COMPANY

Balance Sheet
As of March 31, 2011

232625	AP-P/R Savings & Thrift Vanguard	(796.02)
232627	AP-P/R Garnishments	-
232631	AP-P/R Savings Bonds	-
232650	Accounts Payable - Third Party Supplier	(58,482,006.64)
232655	Retail Customer Accounts - Credits	(19,367,260.89)
	Accounts Payable	(179,284,323.77)
236100	Federal Incomes Taxes Accrued - Current	(1.90)
236110	Federal Incomes Taxes Accrued - Prior Year	0.49
236200	State Income Taxes Accrued - Current	(1,062,948.49)
236210	State Income Taxes Accrued - Prior Year	(5,875,359.33)
236250	Taxes Accrued - Taxes other than income taxes	(54,818,096.53)
236292	Use Tax Payable	(2,182,887.63)
236300	Payroll Taxes Payable	-
236301	Payroll Tax-HI	-
236302	Payroll Tax-OASDI	-
	Taxes Accrued	(63,939,293.39)
237100	Interest Accrued - Customer Deposits	(4,335,307.96)
237200	Interest Accrued - First Mortgage Bonds	(32,215,532.67)
	Interest Accrued	(36,550,840.63)
243000	Obligations under Capital Lease - General	(7,449,964.26)
	Current Portion of Capital Lease Obligation	(7,449,964.26)
236700	FIN 48 Federal Interest & Tax Liability-Current	1.81
236750	FIN 48 State Interest & Tax Liability-Current	(2.97)
	Interest & Tax Liab-Uncertain Tax Positions	(1.16)
236710	Federal Income Tax Payable-Current	(0.01)
236760	State Income Tax Payable-Current	(0.87)
	Income Taxes Payable	(0.88)
235120	Customer Deposits - MD	(29,536,526.45)
235140	Customer Deposits - Washington DC	(19,311,311.76)
241000	Tax Collections Payable - General	(6,015.21)
241101	P/R FWT Payable	-
241102	P/R OASDI Payable	-
241103	P/R HI/MED Payable	-
241104	P/R State W/H Payable	-
241200	Maryland Environmental Surcharge	(172,034.42)
241300	Maryland Sales Tax Payable	(862,925.59)
241335	Gross Receipts Tax Payable	(4,163,154.20)
241340	G/R Tax Payable-Washington DC	(6,762,075.68)
241365	Washington DC Sales Tax Payable	(885,076.70)
241375	Sales Taxes Payable	(3,121.56)
241750	PG County Energy Tax Payable	(8,636,652.82)
242000	Accrued Liab-General	(1,055,283.51)
242009	Accrued Liab-Environmental Site Exp - Short-Term	(685,000.00)
242200	Accrued Liab-Required Health Claims Reserve	(1,384,759.60)

POTOMAC ELECTRIC POWER COMPANY

Balance Sheet
As of March 31, 2011

242201	Accrued Liab-General Liability	(3,376,919.77)
242202	Accrued Liabilities - Workers Comp - Current	(3,903,887.75)
242204	Accrued Liab-Auto Liability	(1,203,753.27)
242208	Accrued Liabilities - Disability - Current	(2,022,450.44)
242209	Accrued Liabilities - Surviving Spouse - Current	(69,960.00)
242400	Accrued Liab-AIP	-
242404	Accrued Liability - PHI Incentive Plan	(350,277.37)
242407	Accrued Liab-Cobra Benefits-Merger/Severance	(43,836.00)
242415	Accrued Severance	-
242449	Accrued Liabilities - SERP - Current	(2,228,688.24)
242461	Accrued Liab-Safety Incentive	(214,048.49)
242467	Accrued Liability - Executive	-
242497	Accrued Liab-Sick Pay Carryover	(7,023,495.22)
242498	Accrued Liab-Vacation	(10,616,029.66)
242531	Accrued Liab - Cashier's Account	5,585.53
242540	Accrued Liab-Unclaimed Monies - Escheat Pending	(1,459,607.18)
242625	Accrued Liab - Other Energy Purchased	(35,051.15)
242636	Accrued Liability - Retail Supplier Deposits	(75,037.93)
242639	Accd Liab-MD Energy Administration Appliance Prgm	501.00
253311	Acc Liab - Deferred Comp ST - Active Plans	(650,000.00)
253312	Acc Liab - Deferred Comp ST -Old Plans	(1,600,000.00)
Other		(108,330,893.44)
Total		(287,608,234.24)
Deferred Credits		

254018	Oth Regulated Liab - Removal Costs - FAS 143	(127,606,237.52)
254173	Regulatory Liability - Mirant Settlement	(578,017.83)
254250	Oth Reg Liab - Asset Retirement Obligation	(473,745.03)
254520	Other Regulatory Liability - MD SOS Energy Costs	(9,931,476.78)
254521	Other Reg Liability - MD SOS Transmission Costs	-
254525	Other Reg Liability - DC SOS Transmission Costs	(4,835,503.08)
254526	Other Reg Liability - DC SOS Administrative Charge	(301,133.24)
254538	Reg Liab-FERC Formula Rate Adj-Transmission Svc	-
254540	Reg Liab - MD Regional Greenhouse Gas Init.Credit	(129,421.32)
254900	SFAS109-Regulatory Liability Electric	(11,490,453.83)
Regulatory Liabilities		(155,345,988.63)
190100	Def Inc Tx-Acc Fed Def Inc Tax	37,116,097.49
190200	Def Inc Tx-Acc State Def Inc Tax	9,555,407.53
190250	Deferred Income Tax Asset-State-NOL	3,638,298.62
190500	Def Inc Tx-Investment Tax Credit-Federal	9,062,489.61
190510	Def Inc Tx-Investment Tax Credit-State	283,786.44
282100	Def Inc Tx - Property - Fed Def Inc Tax	(681,066,363.80)
282200	Def Inc Tx - Property - State Def Inc Tax	(168,948,240.84)
283100	Def Inc Tax-Other-Fed Def Inc Tax	(152,151,024.63)
283150	Deferred Inc Tax Liab-Federal-UTPs/Eff Sttld-L/T	(1,253,925.28)
283200	Def Inc Tax-Other-State Def Inc Tax	(39,085,394.12)
Deferred Income Taxes		(982,848,868.98)

POTOMAC ELECTRIC POWER COMPANY

Balance Sheet
As of March 31, 2011

255000	Accumulated Deferred Investment Tax Credits-Gen'l	(6,147,300.00)
	Deferred Investment Tax Credit	(6,147,300.00)
283700	FIN48 Federal Interest & Tax Liability-Noncurrent	(44,478,546.13)
283750	FIN48 State Interest & Tax Liability-Noncurrent	(12,863,350.60)
	Interest & Tax Liab-Uncertain Tax Positions	(57,341,896.73)
283710	Federal Income Tax Payable-Non-current	(0.23)
283760	State Income Tax Payable-Non-current	(1,868,636.82)
	Income Taxes Payable	(1,868,637.05)
242012	Accrued Liab-Merrill Creek Lease Exp	-
242212	Accrued Liabilities - Workers Comp - Long-term	(21,088,194.76)
242218	Accrued Liabilities - Disability - Long-term	(8,932,025.91)
242219	Accrued Liabilities - Surviving Spouse - Long-term	(733,510.58)
242450	Accrued Liab-SERP	(5,342,039.69)
242611	Accrued Liab-OPEB	(67,554,103.91)
253020	Deferred Credit-Customer Deposits-Spec Bill-Rents	(2,542,449.88)
253021	Deferred Credit-Customer Deposits-Spec Bill-Escrow	(2,325,663.97)
253023	Deferred Credit-Special Billing	(733,884.49)
253028	Deferred Credit - CIS Transfers	7,256.22
253307	Acc Liab - Deferred Comp LT -Old Plans	(8,046,216.67)
253310	Acc Liab - Deferred Comp LT - Active Plans	(813,757.42)
254000	Other Long-Term Liabilities	(2,500,000.00)
254201	Accrued Liab-Environmental Site Exp - Long-Term	(14,003,614.35)
	Other	(134,608,205.41)
	Total	(1,338,160,896.80)
	Long-term Debt	

221100	Bonds Payable - First Mortgage Bonds	(1,547,800,000.00)
224001	Project Financing Debt - Long-Term	(650,000.03)
226000	Bonds Payable-Unamortized Discount - General	8,954,242.59
	Long-term Debt	(1,539,495,757.44)
227000	Obligations under Capital Lease - Noncurrent - Gen	(85,469,384.61)
	Long-term Capital Lease Obligation	(85,469,384.61)
	Total	(1,624,965,142.05)
	Capitalization	

201000	Common Stock Issued - General	(1.00)
	Common Stock	(1.00)
207000	Premium on Capital Stock - General	(8,100,463.75)
209000	Reduction in Par Value - Capital Stock	(496,274,514.00)
210000	Gain on Resale or Canc of Reacq Cap Stk - General	(2,509,762.16)

POTOMAC ELECTRIC POWER COMPANY

Balance Sheet
As of March 31, 2011

211000 Paid in Capital - General	(198,521,141.92)
Additional P.I.C. Common	(705,405,881.83)
216000 Unappropriated Retained Earnings - General	(722,755,439.01)
216200 Dividends Declared-Common Stock	-
Retained Earnings	(722,755,439.01)
Total	(1,428,161,321.84)
Profit for the Period	(17,822,874.40)
Total Capitalization & Liabilities	(4,696,718,469.33)

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Direct Exhibit
DC P.S.C. - July, 2011

Introduced as:
PEPCO _____ (F)-6

POTOMAC ELECTRIC POWER COMPANY

District of Columbia
Analysis of Account 928 - Regulatory Expense
Twelve Months Ending September 30, 2011 (Six Months Actual, Six Months Projected)

Description	OPC Deposits	PSC Deposits	Other, including Outside Experts and Consultants	Total	Distr Only
Cases 100% distribution-related					
766 Productivity Improvement Plan	\$ 25,000	\$ -	\$ 1,105	\$ 26,105	\$ 26,105
945 Investigation into Service, Competition, and Policies	32,790	-	3,031	35,821	35,821
982 Interruption of Electric Service	40,000	-	5,024	45,024	45,024
991 Investigation into Explosions in or around UG Distribution System	-	-	1,006	1,006	1,006
1002 Joint Application for Authorization and Merger Transaction	-	-	2,157	2,157	2,157
1026 Feasibility of Relocating OH Lines and Cables Underground	32,160	-	-	32,160	32,160
1053 Increase in Rates for Sale of Electricity	-	-	93,480	93,480	93,480
1056 DSM Surcharge/AMI	10,600	-	-	10,600	10,600
1062 Investigation into Electric Power Outage	56,375	-	-	56,375	56,375
1071 Investigation into High Energy Bills	-	25,000	-	25,000	25,000
1073 Underground Transmission Lines	-	-	1,913	1,913	1,913
1076 2009 Rate Case	-	-	960,000	960,000	960,000
1082 Integration into Distribution System Reliability	112,000	-	234	112,234	112,234
1083 Implementation of Smart Grid	-	150,145	-	150,145	150,145
Budgeted DC Deposit Orders (Split Evenly between PSC and OPC)	249,500	249,500	-	499,000	499,000
Retail Regulation DC (Charges to Order 5223192, 5236707 and 5236710)	-	-	290,195	290,195	290,195
Cases not allocable to distribution					
1017 DC SOS	-	-	1,094	1,094	-
Total	\$ 558,425	\$ 424,645	\$ 1,359,239	\$ 2,342,309	\$ 2,341,215

POTOMAC ELECTRIC POWER COMPANY

District of Columbia
Analysis of Account 928 - Regulatory Expense
Twelve Months Ended December 31, 2010

Description	OPC Deposits	PSC Deposits	Other, including Outside Experts and Consultants	Total	Distr Only
Cases 100% distribution-related					
766 Productivity Improvement Plan	\$ 25,500	\$ -	\$ 3,727	\$ 29,227	\$ 29,227
945 Investigation into Service, Competition, and Policies	42,790	-	4,720	47,510	47,510
982 Interruption of Electric Service	46,250	-	5,715	51,965	51,965
991 Investigation into Explosions in or around UG Distribution System	-	320,000	3,628	323,628	323,628
1002 Joint Application for Authorization and Merger Transaction	-	-	2,848	2,848	2,848
1026 Feasibility of Relocating OH Lines and Cables Underground	32,160	-	-	32,160	32,160
1053 Increase in Rates for Sale of Electricity	103,230	-	249,280	352,510	352,510
1056 DSM Surcharge/AMI	-	-	8,221	8,221	8,221
1062 Investigation into Electric Power Outage	56,375	-	955	57,330	57,330
1070 Investigation into Non-AMI Demand Response	-	-	1,426	1,426	1,426
1071 Investigation into High Energy Bills	-	25,000	-	25,000	25,000
1073 Underground Transmission Lines	-	-	1,781	1,781	1,781
1076 2009 Rate Case	-	-	(2,112,024)	(2,112,024)	(2,112,024)
1082 Integration into Distribution System Reliability	112,000	-	234	112,234	112,234
1083 Implementation of Smart Grid	-	150,145	-	150,145	150,145
Retail Regulation DC (Charges to Order 5223192, 5236707 and 5236710)	-	-	254,254	254,254	254,254
					-
Cases not allocable to distribution					
8796 Divestiture	-	-	-	-	-
Other					
Billed in Error			(387)	(387)	-
Total	\$ 418,305	\$ 495,145	\$ (1,575,622)	\$ (662,172)	\$ (661,785)

POTOMAC ELECTRIC POWER COMPANY

District of Columbia
Analysis of Account 928 - Regulatory Expense
Twelve Months Ended December 31, 2009

Description	OPC Deposits	PSC Deposits	Other, including Outside Experts and Consultants	Total	Distr Only
Cases 100% distribution-related					
766 Productivity Improvement Plan	\$ 25,500	\$ -	\$ -	\$ 25,500	\$ 25,500
813 Increase in Retail Rates	11,140	-	-	11,140	11,140
982 Interruption of Electric Service	12,800	-	-	12,800	12,800
991 Investigation into Explosions in or around UG Distribution System	-	196,000	-	196,000	196,000
1009 Code of Conduct	16,000	-	-	16,000	16,000
1026 Feasibility of Relocating OH Lines and Cables Underground	-	178,145	-	178,145	178,145
1050 Implementation of Interconnection Standards in DC	2,625	-	-	2,625	2,625
1053 Increase in Rates for Sale of Electricity	20,000	150,000	429,056	599,056	599,056
1056 DSM Surcharge/AMI	12,500	-	1,821	14,321	14,321
1068 Long Term Financing Mechanisms for CAEA	9,240	-	-	9,240	9,240
1071 Investigation into High Energy Bills	58,000	16,000	-	74,000	74,000
1073 Underground Transmission Lines	25,500	-	-	25,500	25,500
1074 Regulatory Asset for Pension Costs	14,160	-	-	14,160	14,160
1076 2009 Rate Case	1,094,278	700,000	484,849	2,279,127	2,279,127
Retail Regulation DC (Charges to Order 5223192, 5236707 and 5236710)			253,330	253,330	253,330
Cases not allocable to distribution					
8796 Divestiture			1,457	1,457	-
Total	\$ 1,301,743	\$ 1,240,145	\$ 1,170,513	\$ 3,712,401	\$ 3,710,944

POTOMAC ELECTRIC POWER COMPANY

District of Columbia
Analysis of Account 928 - Regulatory Expense
Twelve Months Ended December 31, 2008

Description	OPC Deposits	PSC Deposits	Other, including Outside Experts and Consultants	Total	Distr Only
Cases 100% distribution-related					
766 Fuel Adj Clause Audit and Review	\$ 10,500	\$ -	\$ -	\$ 10,500	\$ 10,500
945 Electric Services Market Competition/Divestiture	45,000	-	-	45,000	45,000
982 Interruption of Electric Service	155,000	-	-	155,000	155,000
991 Investigation into Explosions in or around UG Distribution System	-	231,100	-	231,100	231,100
1002 Application for Authorization and Approval of Merger	-	-	3,438	3,438	3,438
1009 Investigation into Code of Conduct for Regulated Gas & Electric companies	50,900	-	-	50,900	50,900
1026 Feasibility of Relocating OH Lines and Cables Underground	-	250,000	-	250,000	250,000
1044 Application for Certificate to Construct 69kv Transmission Lines	(46,577)	-	-	(46,577)	(46,577)
1052 Investigation of Consumer Complaints	-	5,000	-	5,000	5,000
1053 Increase in Rates for Sale of Electricity	240,494	-	267,192	507,686	507,686
1076 2009 DC Rate Case	-	-	55,847	55,847	55,847
Retail Regulation DC (Charges to Orders 5223192, 5236710 and 5235416)	-	-	338,588	338,588	338,588
Cases not allocable to distribution					
930	(4,417)	-	-	(4,417)	-
1023 Investigation into Effect of Mirant Bankruptcy	(442,823)	-	-	(442,823)	-
Total	\$ 8,077	\$ 486,100	\$ 665,065	\$ 1,159,242	\$ 1,606,482

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Introduced as:
PEPCO _____ (F)-7

POTOMAC ELECTRIC POWER COMPANY

Summary of Informational Advertising Expenditures
Twelve Months Ended March 31, 2011

Ad #	Ad Description	Synopsis of Text	Information Conveyed to Customer	Twelve Months Ended March 2011
965	Before You Dig	Call Miss Utility before you dig	General safety - call Miss Utility at 811	\$ 84
966	Wise Energy	How to conserve energy	Summer conservation tips	83
967	My Account	Use My Account to manage your electric bill	Ways My Account can help you manage your electric bill	83
992	Announcement of 6-Point Reliability Plan	What's New at Pepco	Aspects of 6-Point Reliability Plan	910
994	What Pepco is Doing	Pepco continues to prepare for what the future brings	Preparations for future; reliability enhancement	598
999	Emergency Preparedness	Preparing for winter power outage	How to prepare for emergencies/outages	8,215
1002	Neighbors Helping Neighbors/Important Phone Nos	Things you can do to help neighbors in an emergency	Things you can do to get help or provide help; important phone numbers	3,735
1015	Emergency Preparedness/Contacts and Phone Nos	Additional help to seniors from local governments	Help Available to the Seniors; important phone numbers	3,735
	Other Misc:			
	Item charged/credited to acct 909 in error			(525)
	"Lines" bill inserts, other informational brochures			70,592
	Account Management, other misc			14,187
Total Account 909				<u>\$ 101,698</u>
Less: ads that are institutional in nature*				(1,508)
Plus: add-back of accounting charge improperly credited to account 909				<u>525</u>
Informational advertising included in cost of service				<u>\$ 100,715</u>

POTOMAC ELECTRIC POWER COMPANY

Summary of Informational Advertising Expenditures
Twelve Months Ending September 30, 2011
(Six Months Actual; Six Months Projected)

Ad #	Ad Description	Synopsis of Text	Information Conveyed to Customer	Twelve Months Ending Sept 2011
994	What Pepco is Doing	Pepco continues to prepare for what the future brings	Preparations for future; reliability enhancement	\$ 598
999	Emergency Preparedness	Preparing for winter power outage	How to prepare for emergencies/outages	8,215
1002	Neighbors Helping Neighbors	Things you can do to help neighbors in an emergency	Things you can do to get help or provide help; important phone numbers	3,735
1015	Partners in Preparedness	Additional help to seniors from local governments	Help Available to the Seniors; important phone numbers	3,735
Other Miscellaneous				
Item charged/credited to account 909 in error				(525)
"Lines" (Bill Inserts), other informational brochures				70,592
Account Management/Misc				12,227
Projected informational advertising April through September (detail by ad no. not available)				237,028
Total account 909				<u>\$ 335,604</u>
Less: ads that are institutional in nature*				(598)
Plus: add-back of accounting charge improperly credited to account 909				<u>525</u>
Informational advertising included in cost of service				<u>\$ 335,532</u>

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Direct Exhibit
DC P.S.C. - July, 2011

Introduced as:
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Potomac Electric Power Company
Operating Results and Rates of Return

(Dollars in Thousands)

		Unadjusted					Fully Adjusted				
		Rate Base	Operating Income	Actual ROE	Authorized ROE	Revenue Deficiency	Rate Base	Operating Income	Actual ROE	Authorized ROE	Revenue Deficiency
12 months ended	December 31, 2002	\$ 916,537	\$ 64,745 ¹	7.0%	11.1% ²	\$ 28,912	\$ 916,114	\$ 66,347	7.4%	11.1% ²	\$ 26,110
12 months ended	December 31, 2003	967,970	65,706 ¹	6.2%	11.1% ²	33,117	969,215	67,394	7.3%	11.1% ²	30,419
12 months ended	December 31, 2004	974,413	68,528 ¹	7.6%	11.1% ²	27,430	973,909	67,749	7.5%	11.1% ²	28,687
12 months ended	December 31, 2005	990,277	57,368 ¹	5.3%	11.1% ²	46,147	990,277	56,129	5.1%	11.1% ²	48,265
12 months ended	December 31, 2006	930,642	54,607 ¹	5.7%	11.1% ²	41,865	1,004,019	56,073	5.1%	11.1% ²	50,018
12 months ended	December 31, 2007	926,521	47,244 ¹	4.0%	11.1% ²	54,482	994,596	49,119	3.7%	11.1% ²	61,213
12 months ended	December 31, 2008	976,659	67,571 ¹	7.3%	10.0% ³	19,218	1,020,095	60,966 ⁵	5.2%	10.0% ³	36,495
12 months ended	December 31, 2009	988,966	68,517	7.3%	10.0% ³	22,678	1,015,122	66,275	6.5%	10.0% ³	30,206
12 months ended	December 31, 2010	1,069,965	70,543	6.6%	9.625% ⁴	27,189	1,074,888	81,987 ⁶	8.7%	9.625% ⁴	8,312
12 months ended	March 31, 2011	1,089,877	72,670	6.7%	9.625% ⁴	26,490	1,163,660	77,154	6.7%	9.625% ⁴	29,028
12 months ending	September 30, 2011 (6&6)	1,100,652	74,711	7.0%	9.625% ⁴	24,492	1,167,522	76,238	6.5%	9.625% ⁴	31,127

¹ Adjusted to reflect weather normalization of test year revenues

² F.C. 939, Order No. 10646, effective 7/11/95 for bundled, vertically integrated Pepco (pre-divestiture)

³ F.C. 1053, Order No. 14712, effective 2/20/08 for Pepco Distribution-only

⁴ F.C. 1076, Order No. 15710, effective 3/23/10 and Order No. 15864, effective 6/30/10 for Pepco Distribution-only

⁵ Includes annualization of \$28,286 increase approved in F.C. 1053, Order No. 14712

⁶ Includes annualization of \$20,346 increase approved in F.C. No. 1076, Order Nos. 15710, 15864 (Reconsideration)

Potomac Electric Power Company

District of Columbia
Ratemaking Results - Distribution Only
Twelve Months Ending December 31, 2012
(Fully Projected)

(Thousands of Dollars)

Line No.		12 Mos. Ending 12/31/2012 per Witness McGowan (1)	Adjustments for D.C. Cost of Service (2)	Average (Unadjusted) (3)	Revenue Increase Requested at PEPCO (F)-1 (4)	D.C. Adjusted (5)	Revenue to Achieve 10.75% Return on Equity (6)	Adjusted to Reflect 10.75% Return on Equity (7)
	Rate Base							
1	Electric Plant in Service	\$ 2,667,154	\$ (73,957)	\$ 2,593,197		\$ 2,593,197		\$ 2,593,197
2	Accumulated Depreciation/Amortization	(964,430)	34,518	(929,912)		(929,912)		(929,912)
3	Materials and Supplies	21,099		21,099		21,099		21,099
4	Cash Working Capital	13,758		13,758		13,758		13,758
5	Accumulated Deferred Income Taxes	(516,696)		(516,696)		(516,696)		(516,696)
6	Prepaid Pension/OPEB Liab. (net of tax)	48,104		48,104		48,104		48,104
7	Customer Deposits	(23,781)		(23,781)		(23,781)		(23,781)
8	Pepco Portion of Servco Assets	4,201		4,201		4,201		4,201
9	AMI Regulatory Assets		30,397	30,397		30,397		30,397
10	Unamortized Credit Facility Costs					0		0
11	Total Rate Base	<u>\$ 1,249,409</u>	<u>\$ (9,042)</u>	<u>\$ 1,240,367</u>	<u>\$ -</u>	<u>\$ 1,240,367</u>		<u>\$ 1,240,367</u>
12	Operating Revenues							
13	Sale of Electricity	\$ 414,731		\$ 414,731	\$ 42,101	\$ 456,832		
14	Other Revenues	2,317		2,317		2,317		
15	Operating Revenues	<u>\$ 417,048</u>	<u>\$ -</u>	<u>\$ 417,048</u>	<u>\$ 42,101</u>	<u>\$ 459,149</u>	\$ 13,532	\$ 472,681
16	Operating Expenses							
17	Operation and Maintenance	\$ 100,417		\$ 100,417		\$ 100,417		\$ 100,417
18	Depreciation/Amortization	70,146	2,860	73,006		73,006		73,006
19	Other Taxes	145,482		145,482		145,482		145,482
20	D.C. Income Tax	5,290	(255)	5,035	\$ 4,200	9,235	\$ 1,350	10,585
21	Federal Income Tax	19,301	(806)	18,495	13,265	31,760	4,264	36,024
22	Total Operating Expenses	<u>\$ 340,636</u>	<u>\$ 1,799</u>	<u>\$ 342,435</u>	<u>\$ 17,465</u>	<u>\$ 359,900</u>	<u>\$ 5,614</u>	<u>\$ 365,514</u>
23	Operating Income	<u>\$ 76,412</u>	<u>\$ (1,799)</u>	<u>\$ 74,613</u>	<u>\$ 24,636</u>	<u>\$ 99,249</u>	<u>\$ 7,919</u>	<u>\$ 107,168</u>
24	D.C. Jurisdictional Return on Rate Base	<u>6.12%</u>		<u>6.02%</u>		<u>8.00%</u>		<u>8.64%</u>
	Less Weighted Cost of:							
	Long Term Debt	3.35%		3.35%		3.35%		3.35%
	Preferred Stock	0.00%		0.00%		0.00%		0.00%
	Net amount available for common equity	2.77%		2.67%		4.65%		5.29%
	Common Equity ratio	49.23%		49.23%		49.23%		49.23%
	D.C. Jurisdictional Return on Equity	5.62%		5.41%		9.45%		10.75%